CHESAPEAKE ENERGY

2021
ANNUAL REPORT

Answering the Call for Affordable, Reliable, Lower Carbon Energy

Dear Fellow Shareholders,


We sit at a critical point in human history. Inflation is increasing at its fastest rate in 40 years, stifling economic growth and impacting the cost of nearly every product we have come to rely on. Russia's senseless invasion of Ukraine and the suffering it has brought to the Ukrainian people has been shocking and heartbreaking. This gratuitous war and the economic impact brought on by decades of failed public policy has reinforced that we must think long and hard about how to increase the world's energy security, forcing a long-overdue conversation about where energy comes from, its cost and what it means to people's daily lives.

This conversation around energy sourcing has surfaced the debate about whether climate concerns "or" energy security should be the determining factor in setting energy policy. We are strident in our view that "or" is the wrong question and policy makers should be seeking solutions that deliver lower carbon energy AND security from geopolitical pressure AND reliable deliverability AND affordability. **Chesapeake is "Answering the Call" to deliver energy that meets all of these needs.**

Constructive and honest dialogue between industry, government officials and NGO groups is needed to develop practical long-term solutions. We recognize to be included in constructive dialogue on energy supply our industry must commit to reducing our carbon footprint further and be accountable for those reductions over time.

Delivering reliable, affordable, lower carbon energy will not happen in a vacuum. First and foremost, it requires that Chesapeake build a sustainable business, and 2021 proved to be a foundational year in that effort. Behind a committed workforce and a new Board of Directors and management team, Chesapeake demonstrated that it has the strategy, assets and people to become a standard-bearer for the modern energy industry.

This starts with our relentless focus on safely and responsibly executing the critical value drivers for our company. In 2021, we made significant strides across each of these areas, and we are well on our way to building upon that success in 2022 and beyond:

VALUE DRIVERS	2021	2022 AND BEYOND
Superior capital returns	• ~$1.26 billion in adjusted free cash flow • ~35% reinvestment rate of adjusted EBITDAX	• >$9 billion of estimated adjusted free cash flow through 2026 (based on February 2022 commodity prices)
Returning cash to shareholders	• Initiated and increased base dividend • Established variable dividend program • Authorized share and warrant repurchase program	• $0.9 – $1.1 billion estimated total dividends payable in 2022 • Plan to repurchase up to $1 billion of equity by YE 2023
Maintaining balance sheet strength	• Committed to maintaining <1x long term leverage	• Pro forma ~0.7x 2022E net debt-to-EBITDAX ratio
ESG excellence across all aspects of our business	• First company to independently certify its Haynesville operations as responsibly sourced; earned Grade "A" MiQ and EO100 certifications • Aligned Executive Compensation Program • Established Board-level ESG Committee • Installed ~1,800 continuous methane monitoring devices	• Delivering ~6 bcf/d of certified responsibly sourced gas by YE 2022 • Retrofitting >19,000 pneumatic devices — reducing reported GHG emissions by ~40% and methane emissions by ~80%

Our commitment to stakeholders is that we will not cut corners in our pursuit of excellence. This starts with our firm belief that above all else, we must be stewards of the communities in which we live and operate. This is a responsibility we do not take lightly, and it is one that guides our values and culture. It is why we fervently embrace a lower carbon future and are proud to play an important role in meeting the ambitions of the Paris Agreement. It is also why we are constantly innovating across all aspects of our business, challenging the status quo, and driving for solutions to make us a stronger, more competitive enterprise.

While a single company may not solve the energy security challenge facing the world today, we believe Chesapeake has a unique opportunity to play a leadership role in that undertaking. Our desire to answer the call for reliable, affordable, lower carbon energy unites our employees, management team and Board, and we are eager to continue our pursuit of that worthy mission.

Thank you for your investment in our company.

Domenic J. "Nick" Dell'Osso, Jr.
President, Chief Executive Officer and Director

Michael A. Wichterich
Executive Chairman of the Board

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

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

For the transition period from __________ to __________

Commission File No. 001-13726

CHESAPEAKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 North Western Avenue, Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Trading Symbol(s)**	**Name of Each Exchange on Which Registered**
Common Stock, $0.01 par value per share	CHK	The Nasdaq Stock Market LLC
Class A Warrants to purchase Common Stock	CHKEW	The Nasdaq Stock Market LLC
Class B Warrants to purchase Common Stock	CHKEZ	The Nasdaq Stock Market LLC
Class C Warrants to purchase Common Stock	CHKEL	The Nasdaq Stock Market LLC

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐

Smaller Reporting Company ☐ Emerging Growth Company ☐

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

Indicate by check mark whether the registrant has filed 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 ☒

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2021, was approximately $1.6 billion. As of February 21, 2022, there were 118,558,307 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2022 Annual Meeting of Shareholders are incorporated by reference in Part III.

Definitions

Unless the context otherwise indicates, references to “us,” “we,” “our,” “ours,” “Chesapeake,” the “Company” and “Registrant” refer to Chesapeake Energy Corporation and its consolidated subsidiaries. All monetary values, other than per unit and per share amounts, are stated in millions of U.S. dollars unless otherwise specified. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

“Adjusted Free Cash Flow” (a non-GAAP measure) means net cash provided by operating activities (GAAP) less cash capital expenditures, adjusted to exclude certain items management believes affect the comparability of operating results.

“ASC” means Accounting Standards Codification.

“Backstop Commitment Agreement” means that certain Backstop Commitment Agreement, dated as of June 28, 2020, by and between Chesapeake and the Backstop Parties, as may be further amended, modified, or supplemented from time to time, in accordance with its terms.

“Backstop Parties” means the members of the FLLO Ad Hoc Group that are signatories to the Backstop Commitment Agreement and Franklin Advisers, Inc., as investment manager on behalf of certain funds and accounts.

“Bankruptcy Code” means Title 11 of the United States Code, 11 U.S.C. §§ 101–1532, as amended.

“Bankruptcy Court” means the United States Bankruptcy Court for the Southern District of Texas.

“Bbl” or “Bbls” means barrel or barrels.

“Bcf” means billion cubic feet.

“Boe” means barrel of oil equivalent. Natural gas proved reserves and production are converted to Boe, at the pressure and temperature base standard of each respective state in which the natural gas is produced, at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of natural gas and oil. NGL proved reserves and production are converted to Boe on a one-to-one basis with oil.

“Chapter 11 Cases” means, when used with reference to a particular Debtor, the case pending for that Debtor under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court, and when used with reference to all the Debtors, the procedurally consolidated Chapter 11 cases pending for the Debtors in the Bankruptcy Court.

“Chief” means Chief E&D Holdings, LP.

“Chief Acquisition” means Chesapeake’s planned acquisition of Chief E&D Holdings, LP and associated non-operated interests held by affiliates of Tug Hill, Inc., which, subject to the satisfaction or waiver of certain closing conditions, including certain regulatory approvals, is expected to close in the first quarter of 2022.

“Class A Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan, the Class B Warrants, and the Class C Warrants), at an initial exercise price per share of $27.63. The Class A Warrants are exercisable from the Effective Date until February 9, 2026.

“Class B Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan and the Class C Warrants), at an initial exercise price per share of $32.13. The Class B Warrants are exercisable from the Effective Date until February 9, 2026.

“Class C Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan), at an initial exercise price per share of $36.18. The Class C Warrants are exercisable from the Effective Date until February 9, 2026.

“Completion” means the process of treating a drilled well followed by the installation of permanent equipment for the production of oil, natural gas or natural gas liquids, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

“Confirmation Order” means the order confirming the Fifth Amended Joint Chapter 11 Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates, Docket No. 2915, entered by the Bankruptcy Court on January 16, 2021.

“Debtors” means the Company, together with all of its direct and indirect subsidiaries that have filed the Chapter 11 Cases.

“Developed Acreage” means acres which are allocated or assignable to producing wells or wells capable of production.

“DIP Facility” means that certain debtor-in-possession financing facility documented pursuant to the DIP Documents and DIP Order.

“Dry Well” means a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

“Effective Date” means February 9, 2021.

“Exit Credit Facility” means the reserve-based revolving credit facility available upon emergence from bankruptcy.

“Exploratory Well” means 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.

“FLLO Term Loan Facility” means the facility outstanding under the FLLO Term Loan Facility Credit Agreement.

“FLLO Term Loan Facility Credit Agreement” means that certain Term Loan Agreement, dated as of December 19, 2019 ((i) as supplemented by that certain Class A Term Loan Supplement, dated as of December 19, 2019 (as amended, restated or otherwise modified from time to time), by and among Chesapeake, as borrower, the Debtor guarantors party thereto, GLAS USA LLC, as administrative agent, and the lenders party thereto, and (ii) as further amended, restated, or otherwise modified from time to time), by and among Chesapeake, the Debtor guarantors party thereto, GLAS USA LLC, as administrative agent, and the lenders party thereto.

“Formation” means a succession of sedimentary beds that were deposited under the same general geologic conditions.

“Free Cash Flow” (a non-GAAP measure) means net cash provided by operating activities (GAAP) less cash capital expenditures.

“GAAP” means U.S. generally accepted accounting principles.

“General Unsecured Claim” means any Claim against any Debtor that is not otherwise paid in full during the Chapter 11 Cases pursuant to an order of the Bankruptcy Court and is not an Administrative Claim, a Priority Tax Claim, an Other Priority Claim, an Other Secured Claim, a Revolving Credit Facility Claim, a FLLO Term Loan Facility Claim, a Second Lien Notes Claim, an Unsecured Notes Claim, an Intercompany Claim, or a Section 510(b) Claim.

“Gross Acres or Gross Wells” means the total acres or wells, as the case may be, in which a working interest is owned.

“MBbls” means thousand barrels.

“MMBbls” means million barrels.

“MBoe” means thousand Boe.

“MMBoe” means million Boe.

“Mcf” means thousand cubic feet.

“MMcf” means million cubic feet.

“Net Acres or Net Wells” means the sum of the fractional working interests owned in gross acres or gross wells.

“New Common Stock” means the single class of common stock issued by Reorganized Chesapeake on the Effective Date.

“NGL” means natural gas liquids.

“NYMEX” means New York Mercantile Exchange.

“OPEC” means Organization of the Petroleum Exporting Countries.

“Petition Date” means June 28, 2020, the date on which the Debtors commenced the Chapter 11 Cases.

“Plan” means the Fifth Amended Joint Chapter 11 Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates, attached as Exhibit A to the Confirmation Order.

“Play” means a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil, natural gas and NGL reserves.

“Present Value of Estimated Future Net Revenues or PV-10 (non-GAAP)” means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

“Price Differential” means the difference in the price of oil, natural gas or NGL received at the sales point and the NYMEX price.

“Productive Well” means a well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

“Proved Developed Reserves” means reserves that can be expected to be recovered 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.

“Proved Properties” means properties with proved reserves.

“Proved Reserves” As used in this report, proved reserves has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part proved oil and natural gas reserves are 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 the estimation.

“Proved Undeveloped Reserves (PUDs)” means 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. Reserves on undrilled acreage are 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.

“Put Option Premium” means a nonrefundable aggregate fee of $60 million, which represents 10 percent of the Rights Offering Amount, payable to the Backstop Parties in accordance with, and subject to the terms of the

Backstop Commitment Agreement based on their respective backstop commitment percentages at the time such payment is made.

“Reservoir” means 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.

“Rights Offering” means the New Common Stock rights offering for the Rights Offering Amount consummated by the Debtors on the Effective Date.

“SEC” means United States Securities and Exchange Commission.

“Second Lien Notes” means the 11.50% senior notes due 2025 issued by Chesapeake pursuant to the Second Lien Notes Indenture.

“Second Lien Notes Claim” means any Claim on account of the Second Lien Notes.

“Standardized Measure” means the discounted future net cash flows relating to proved reserves based on the means of the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period). The standardized measure differs from the PV-10 measure only because the former includes the effects of estimated future income tax expenses.

“Tranche A Loans” means the fully revolving loans made under and on the terms set forth under the Exit Credit Facility which will be partially funded on the Effective Date, will have a scheduled maturity of 3 years from the Effective Date, and shall at all times be repaid prior to the repayment of the Tranche B Loans.

“Tranche B Loans” means term loans made under and on the terms set forth under the Exit Credit Facility which will be fully funded on the Effective Date, will have a scheduled maturity of 4 years from the Effective Date, will be repaid or prepaid only after there are no Tranche A Loans outstanding, and once so prepaid or repaid, may not be reborrowed.

“Undeveloped Acreage” means acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved reserves.

“Unproved Properties” means properties with no proved reserves.

“Vine Acquisition” means Chesapeake’s acquisition of Vine Energy Inc. which closed on November 1, 2021.

“Vine” means Vine Energy Inc.

“Volumetric Production Payment (VPP)” means a limited-term overriding royalty interest in oil and natural gas reserves that: (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves, if any, after the scheduled production volumes have been delivered.

“Warrants” means collectively, the Class A Warrants, Class B Warrants and Class C Warrants.

“Working Interest” means the operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

“WTI” means West Texas Intermediate.

“/Bbl” means per barrel.

“/Boe” means per Boe.

“/Mcf” means per Mcf.

“2019 Predecessor Period” means the year ended December 31, 2019.

“2020 Predecessor Period” means the year ended December 31, 2020.

“2021 Predecessor Period” means the period of January 1, 2021 through February 9, 2021.

“2021 Successor Period” means the period of February 10, 2021 through December 31, 2021.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). Forward-looking statements include our current expectations or forecasts of future events, including matters relating to the continuing effects of the COVID-19 pandemic and the impact thereof on our business, financial condition, results of operations and cash flows, the potential effects of the Plan restructuring on our operations, management, and employees, actions by, or disputes among or between, members of OPEC+ and other foreign oil-exporting countries, market factors, market prices, our ability to meet debt service requirements, our ability to continue to pay cash dividends, the amount and timing of any cash dividends, our ESG initiatives, and the other items discussed in the Introduction to Item 7 of Part II of this report. In this context, forward-looking statements often address our expected future business, financial performance and financial condition, and often contain words such as "expect," “could,” “may,” "anticipate," "intend," "plan," “ability,” "believe," "seek," "see," "will," "would," “estimate,” “forecast,” "target," “guidance,” “outlook,” “opportunity” or “strategy.”

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- the ability to execute on our business strategy following emergence from bankruptcy;
- the impact of the COVID-19 pandemic and its effect on our business, financial condition, employees, contractors, vendors and the global demand for oil and natural gas and U.S. and world financial markets;
- risks related to the Vine Acquisition, including our ability to successfully integrate the business of Vine into the Company and achieve the expected synergies from the Vine Acquisition within the expected timeframe;
- risks related to the Chief Acquisition, including a delay or failure to complete the Chief Acquisition caused by a failure to receive required regulatory approvals or satisfy or waive, as applicable, other closing conditions to the Chief Acquisition, and if the Chief Acquisition is completed, our ability to successfully integrate the business of Chief into the Company and achieve the expected synergies from the Chief Acquisition within the expected timeframe;
- our ability to comply with the covenants under our Exit Credit Facility and other indebtedness;
- our ability to realize our anticipated cash cost reductions;
- the volatility of oil, natural gas and NGL prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to replace reserves and sustain production;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;

- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- legislative, regulatory and environmental, social and governance (“ESG”) initiatives, including as a result of the change in the U.S. presidential administration, addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- effects of purchase price adjustments and indemnity obligations; and
- other factors that are described under *Risk Factors* in Item 1A of Part I of this Annual Report on Form 10-K (this “Form 10-K” or this “report”).

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures in this report and our other filings with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

PART I

ITEM 1. Business

Unless the context otherwise requires, references to “Chesapeake,” the “Company,” “us,” “we” and “our” in this report are to Chesapeake Energy Corporation together with its subsidiaries. Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our main telephone number at that location is (405) 848-8000.

Our Business

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties to produce oil, natural gas and NGL from underground reservoirs. We own a large and geographically diverse portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 8,200 gross oil and natural gas wells.

On June 28, 2020, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Bankruptcy Court confirmed the Plan in a bench ruling on January 13, 2021 and entered the Confirmation Order on January 16, 2021. The Debtors emerged from bankruptcy on February 9, 2021. Upon emergence, all existing equity was canceled and New Common Stock was issued to the previous holders of our FLLO Term Loan Facility, Second Lien Notes, senior unsecured notes and certain general unsecured creditors whose claims were impaired as a result of our bankruptcy, as well as to other parties as set forth in the Plan, including to other parties participating in a $600 million rights offering. Upon emergence from bankruptcy, we adopted fresh start accounting, which resulted in us becoming a new entity for financial reporting purposes. Accordingly, the consolidated financial statements on or after February 9, 2021 are not comparable to the consolidated financial statements prior to that date. To facilitate our discussion in this report, we refer to the post-emergence reorganized company as the “Successor” and the pre-emergence company as the “Predecessor.” See Note 2 and Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of our bankruptcy, the resulting reorganization and fresh start accounting.

On November 1, 2021, we completed our acquisition of Vine, an energy company focused on the development of natural gas properties in the over-pressured stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana. The Vine Acquisition strengthens Chesapeake’s competitive position, meaningfully increasing our Free Cash Flow outlook and deepening our inventory of premium natural gas locations, while preserving the strength of our balance sheet.

On January 24, 2022, we entered into a definitive agreement to acquire Chief and associated non-operated interests held by affiliates of Tug Hill, Inc. (“Tug Hill”), for $2.0 billion in cash and approximately 9.44 million common shares. Chief and Tug Hill hold producing assets and an inventory of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania. The cash portion of the Chief Acquisition will be financed with cash on hand and the use of our Exit Credit Facility. The Chief Acquisition, which is subject to customary closing conditions, including certain regulatory approvals, is expected to close by the end of the first quarter of 2022.

On January 24, 2022, we entered into an agreement to sell our Powder River Basin assets in Wyoming to Continental Resources, Inc. for approximately $450 million in cash. The transaction, which is subject to certain customary closing conditions, is expected to close in the first quarter of 2022.

The completion of these transactions will clarify and strengthen our asset portfolio, concentrating on three operating areas and advancing our highest-return assets in the Marcellus and Haynesville gas basins.

Information About Us

We make available, free of charge on our website at *chk.com,* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent news releases. Documents and information on our website are not incorporated by reference herein.

The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Chesapeake, that file electronically with the SEC.

Business Strategy

Consistent returns, sustainable future. Our strategy is to create shareholder value by generating sustainable Free Cash Flow from our oil and natural gas development and production activities. We continue to focus on improving margins through operating efficiencies and financial discipline and improving our Environmental, Social, and Governance ("ESG") performance. To accomplish these goals, we intend to allocate our human resources and capital expenditures to projects we believe offer the highest cash return on capital invested, to deploy leading drilling and completion technology throughout our portfolio and to take advantage of acquisition and divestiture opportunities to strengthen our portfolio. We also intend to continue to dedicate capital to projects that reduce the environmental impact of our oil and natural gas producing activities. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation and general and administrative) per barrel of oil equivalent production through operational efficiencies, including but not limited to improving our production volumes from existing wells. We believe that we have emerged from Chapter 11 bankruptcy as a fundamentally stronger company, built to generate sustainable Free Cash Flow with a strengthened balance sheet, geographically diverse asset base and continuously improving ESG performance.

Maintain low leverage and strong liquidity. Subsequent to our emergence from Chapter 11 bankruptcy, we believe that maintaining low net leverage is integral to our business strategy and will allow us to maintain lower fixed costs, improve our margins and maintain the flexibility of our capital program.

Returns-focused capital reinvestment strategy. Our business focus will be on optimizing the development of our large, geographically diverse resource base with a prioritization of generating high cash returns on capital invested. We expect our maintenance capital program to yield in excess of annual production of 700 mboe per day and generate significant Free Cash Flow at today's prevailing commodity market prices.

Low-cost operator with expected top-quartile cash costs. We expect to continue to focus on our cost optimization initiatives.

Continue efforts to reduce greenhouse gas (GHG) emissions and operate in an environmentally responsible manner with a goal of net zero direct GHG emissions by 2035. We are committed to operating our business responsibly and protecting the environments in which we operate. We eliminated routine flaring on all new wells completed in 2021, and plan to accomplish the same on all wells enterprise-wide by 2025. We reduced our methane loss rate to 0.08% and our GHG intensity to 5.0 as of December 31, 2021.

Manage commodity price exposure and ensure stability through prudent hedging strategy. We employ a prudent hedging strategy, which is aligned with our capital expenditure program and is designed to manage our exposure to commodity price volatility, ensure the stability of our cash flows and mitigate our risks to realizing attractive cash returns on capital invested. As of February 21, 2022, we have 11 mmbbls and 899 bcf of expected 2022 production, representing 58% and 68% of 2022 forecasted oil and natural gas production, hedged at prices of $44.30/bbl and $2.69/mcf, respectively, for swaps and $3.21/mcf to $4.26/mcf, respectively, for collars. Additionally, as of February 21, 2022, we have hedged 6 mmbbl and 467 bcf of expected 2023 oil and natural gas production at prices of $47.17/bbl and $2.69/mcf, respectively, for swaps and $65.00/bbl to $79.09/bbl and $3.03/mcf to $4.02/mcf, respectively, for collars. Metrics include hedges that are contingent upon the closing of the Chief Acquisition.

Operating Areas

We focus our acquisition, exploration, development and production efforts in the geographic operating areas described below.

Marcellus - Northern Appalachian Basin in Pennsylvania.

Haynesville - Haynesville/Bossier Shales in Northwestern Louisiana.

Eagle Ford - Eagle Ford Shale in South Texas.

Powder River Basin - Stacked pay in Wyoming (purchase and sale agreement to divest executed on January 24, 2022, and which, subject to the satisfaction or waiver of certain closing conditions, is expected to close in the first quarter of 2022).

Well Data

As of December 31, 2021, we held an interest in approximately 8,200 gross productive wells, including 6,500 wells in which we held a working interest and 1,700 wells in which we held an overriding or royalty interest. Of the 6,500 (4,100 net) wells in which we held a working interest, 3,000 (1,700 net) wells were classified as productive natural gas wells and 3,500 (2,400 net) wells were classified as productive oil wells. During 2021, excluding sold properties, we operated 5,700 gross wells and held a non-operating working interest in 800 gross wells. We also completed 126 gross (74 net) wells as operator and participated in another 13 gross (1 net) wells completed by other operators. We operate approximately 98% of our current daily production volumes.

Drilling Activity

The following table sets forth the wells we completed or participated in during the periods indicated. In the table, "gross" refers to the total wells in which we had a working interest and "net" refers to gross wells multiplied by our working interest:

	2021				2020				2019			
	Gross	**%**	**Net**	**%**	**Gross**	**%**	**Net**	**%**	**Gross**	**%**	**Net**	**%**
Development:												
Productive	137	100	74	100	203	100	126	100	414	100	271	100
Dry	—	—	—	—	—	—	—	—	—	—	—	—
Total	137	100	74	100	203	100	126	100	414	100	271	100
Exploratory:												
Productive	2	100	1	100	—	—	—	—	1	20	1	20
Dry	—	—	—	—	2	100	2	100	4	80	4	80
Total	2	100	1	100	2	100	2	100	5	100	5	100

The following table shows the wells we completed or participated in by operating area:

	2021		2020		2019	
	Gross Wells	**Net Wells**	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
Marcellus	83	34	79	33	44	22
Haynesville	40	31	21	19	22	16
Eagle Ford	12	7	86	65	233	164
Powder River Basin	4	3	12	9	75	57
Mid-Continent	—	—	5	—	40	12
Other	—	—	2	2	5	5
Total	139	75	205	128	419	276

As of December 31, 2021, we had 55 gross (32 net) wells in the process of being drilled or completed.

Production Volumes, Sales Prices, Production Expenses and Gathering, Processing and Transportation Expenses

The following table sets forth information regarding our net production volumes, average sales price received for our production, average sales price of our production combined with our realized gains or losses on derivatives and production and gathering, processing and transportation expenses per boe for the periods indicated:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Net Production:				
Oil (mmbbl)	23	3	37	43
Natural gas (bcf)	727	80	685	728
NGL (mmbbl)	7	1	11	12
Oil equivalent (mmboe)	150	18	163	177
Average Sales Price of Production:				
Oil ($ per bbl)	$ 69.07	$ 53.21	$ 38.16	$ 59.16
Natural gas ($ per mcf)	$ 3.61	$ 2.45	$ 1.73	$ 2.45
NGL ($ per bbl)	$ 31.37	$ 25.92	$ 11.55	$ 15.62
Oil equivalent ($ per boe)	$ 29.19	$ 22.63	$ 16.84	$ 25.57
Average Sales Price (including realized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 49.06	$ 46.85	$ 56.74	$ 60.00
Natural gas ($ per mcf)	$ 2.62	$ 2.52	$ 1.97	$ 2.60
NGL ($ per bbl)	$ 31.42	$ 25.55	$ 11.55	$ 15.62
Oil equivalent ($ per boe)	$ 21.46	$ 21.72	$ 22.09	$ 26.42
Expenses ($ per boe):				
Production	$ 1.97	$ 1.80	$ 2.29	$ 2.94
Gathering, processing and transportation	$ 5.17	$ 5.78	$ 6.64	$ 6.13

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2021, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value of estimated future net revenue ("PV-10") and the standardized measure of discounted future net cash flows ("standardized measure"). None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2021			
	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
Proved developed	166	4,246	62	935
Proved undeveloped	44	3,578	20	661
Total proved[(a)]	210	7,824	82	1,596

	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue[(b)]	$ 14,502	$ 8,776	$ 23,278
Present value of estimated future net revenue (PV-10)[(b)]	$ 8,654	$ 5,057	$ 13,711
Standardized measure[(b)]			$ 12,287

(a) Haynesville, Marcellus, and Eagle Ford accounted for approximately 39%, 36%, and 23% respectively, of our estimated proved reserves by volume as of December 31, 2021.

(b) Estimated future net revenue represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using pricing differentials and costs under existing economic conditions as of December 31, 2021, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2021. The prices used in our PV-10 measure were $66.56 per bbl of oil and $3.60 per mcf of natural gas, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2021. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense of $1.424 billion as of December 31, 2021.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10, a non-GAAP measure, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A comparison of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

As of December 31, 2021, our proved reserve estimates included 661 mmboe of reserves classified as proved undeveloped, compared to 60 mmboe as of December 31, 2020. Presented below is a summary of changes in our proved undeveloped reserves (“PUDs”) for 2021:

	Total (mmboe)
Proved undeveloped reserves, beginning of period (Predecessor)	60
Extensions and discoveries	321
Revisions of previous estimates	145
Conversion to proved developed reserves	(60)
Purchase of reserves-in-place	195
Proved undeveloped reserves, end of period (Successor)	661

As of December 31, 2021, all PUDs were planned to be developed within five years of original recording. In 2021, we invested approximately $97 million to convert 60 mmboe of PUDs to proved developed reserves. In 2022, we estimate that we will invest approximately $794 million for PUD conversion. We added 321 mmboe of proved undeveloped reserves through extensions and discoveries following our emergence from bankruptcy on February 9, 2021 and certainty regarding our ability to finance the development of our proved reserves over a five-year period. In addition, during 2021, we recorded an upward revision of 145 mmboe from previous estimates due to lateral length adjustments, performance and updates to our five-year development plan. We also added 195 mmboe of proved undeveloped reserves through purchase of reserves-in-place related to the Vine Acquisition.

The future net revenue attributable to our estimated PUDs was $8.776 billion and the present value was $5.057 billion as of December 31, 2021. These values were calculated assuming that we will expend approximately $2.7 billion to develop these reserves ($794 million in 2022, $814 million in 2023, $539 million in 2024, $378 million in 2025 and $217 million in 2026). The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity prices and the availability of capital. Our developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as unexpected developmental drilling results, title issues and infrastructure availability or constraints.

Of our 1,596 mmboe of proved developed reserves as of December 31, 2021, approximately 20 mmboe, or 1%, were non-producing.

Our ownership interest used for calculating proved reserves and the associated estimated future net revenue assumes maximum participation by other parties to our farm-out and participation agreements.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2021, 2020 and 2019, along with the changes in quantities and standardized measure of the reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and 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 made by different engineers often vary. Accordingly, reserve estimates often differ from the actual quantities of oil, natural gas and NGL that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. See *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report for further discussion of our reserve quantities.

Reserves Estimation

Our Corporate Reserves Department prepared approximately 9% by volume, and approximately 4% by value, of our estimated proved reserves as of December 31, 2021, disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

Our Director – Corporate Reserves, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for coordinating any reserves work conducted by a third-party engineering firm. Her qualifications include the following:

- Over 19 years of practical experience in the oil and gas industry, with over 16 years in reservoir engineering;
- Bachelor of Science degree in Geology and Environmental Sciences;
- Master's Degree in Petroleum and Natural Gas Engineering;
- Executive MBA; and
- member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserve estimates. Each of our Corporate Reserves Engineers has significant engineering experience in reserve estimation. Our engineering technicians have a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field. We maintain a continuous education program for our engineers and technicians on new technologies and industry advancements as well as refresher training on basic skills and analytical techniques.

We maintain internal controls such as the following to ensure the reliability of reserves estimations:

- We follow comprehensive SEC-compliant internal policies to estimate and report proved reserves. Reserve estimates are made by experienced reservoir engineers or under their direct supervision. All material changes are reviewed and approved by Corporate Reserves Engineers.
- The Corporate Reserves Department reviews our proved reserves at the close of each quarter.
- Each quarter, Reservoir Managers, the Director – Corporate Reserves, the Vice Presidents of each operating area and the Vice President of Corporate and Strategic Planning review all significant reserves changes and all new proved undeveloped reserves additions.
- The Corporate Reserves Department reports independently of our operations.
- The five-year PUD development plan is reviewed and approved annually by the Director – Corporate Reserves and the Vice President of Corporate and Strategic Planning.

We engaged LaRoche Petroleum Consultants, Ltd., a third-party engineering firm, to prepare approximately 91% by volume, and approximately 96% by value, of our estimated proved reserves as of December 31, 2021. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the preparation of our reserve estimates are set forth below.

- Over 40 years of practical experience in the estimation and evaluation of reserves;
- licensed professional engineer in the State of Texas; and
- Bachelor of Science and Master of Science degrees in Petroleum Engineering.

Acreage

The following table sets forth our gross and net developed and undeveloped oil and natural gas leasehold and fee mineral acreage as of December 31, 2021. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our unexercised options to acquire additional acreage.

	Developed Leasehold		Undeveloped Leasehold		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)					
Marcellus	556	339	216	172	772	511
Haynesville	359	323	33	23	392	346
Eagle Ford	678	478	235	133	913	611
Powder River Basin	106	86	126	95	232	181
Other[(a)]	231	212	1,256	1,195	1,487	1,407
Total	1,930	1,438	1,866	1,618	3,796	3,056

(a) Includes 1.2 million net acres retained in the 2016 divestiture of our Devonian Shale assets, in which we retained all rights below the base of the Kope formation.

Most of our leases have a three- to five-year primary term, and we manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning non-core divestitures to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The acreage in the table above includes a total of 0.1 million net acres subject to expiration in the next three years.

Marketing

The principal function of our marketing operations is to provide oil, natural gas and NGL marketing services, including commodity price structuring, securing and negotiating of gathering, hauling, processing and transportation services, contract administration and nomination services for us and other interest owners in Chesapeake-operated wells. The marketing operations also provide other services for our exploration and production activities, including services to enhance the value of oil and natural gas production by aggregating volumes sold to various intermediary markets, end markets and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received.

Generally, our oil production is sold under market-sensitive short-term or spot price contracts. Natural gas and NGL production are sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. Under the terms of our percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Under our percentage-of-index contracts, the price we receive is tied to published indices.

We have entered into long-term gathering, processing, and transportation contracts with various parties that require us to deliver fixed, determinable quantities of production over specified periods of time. Certain of our contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of commitments.

Major Customers

For the 2021 Successor Period, sales to Valero Energy Corporation and Energy Transfer Crude Marketing accounted for approximately 14% and 11%, respectively, of total revenues (before the effects of hedging). For the 2021 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% of total revenues (before the effects of hedging). For the 2020 and 2019 Predecessor Periods, sales to Valero Corporation constituted 17% and 12% of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2021 Successor Period or 2021, 2020 or 2019 Predecessor Periods.

Competition

We compete with both major integrated and other independent oil and natural gas companies in all aspects of our business to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than us. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources, including wind, solar and electric power. We believe that our technological expertise, combined with our exploration, land, drilling and production capabilities and the experience of our management team, enables us to compete effectively.

Public Policy and Government Regulation

All of our operations are conducted onshore in the United States. Our industry is subject to a wide range of regulations, laws, rules, taxes, fees and other policy implementation actions that have been pervasive and are under constant review for amendment or expansion. Numerous government agencies have issued extensive regulations that are binding on our industry, some of which carry substantial penalties for failure to comply. These laws and regulations increase the cost of doing business and consequently affect profitability. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. We actively monitor regulatory developments applicable to our industry in order to anticipate, design and implement required compliance activities and systems. The following are significant areas of government control and regulation affecting our operations.

Exploration and Production, Environmental, Health and Safety and Occupational Laws and Regulations

Our operations are subject to federal, tribal, state, and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to, the following:

- reporting of workplace injuries and illnesses;
- industrial hygiene monitoring;
- worker protection and workplace safety;
- approval or permits to drill and to conduct operations;
- provision of financial assurances (such as bonds) covering drilling and well operations;
- calculation and disbursement of royalty payments and production taxes;
- seismic operations/data;
- location, drilling, cementing and casing of wells;
- well design and construction of pad and equipment;
- construction and operations activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species, their habitats, or sites of cultural significance;
- method of well completion and hydraulic fracturing;
- water withdrawal;

- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- emissions and discharges permitting;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage, maintenance, monitoring and the restoration of properties associated with well pads, pipelines, impoundments and access roads;
- plugging and abandoning of wells; and
- transportation of production.

Shortly after taking office in January 2021, President Biden issued a series of executive orders designed to address climate change and requiring agencies to review environmental actions taken by the Trump administration, as well as a memorandum to departments and agencies to refrain from proposing or issuing rules until a departmental or agency head appointed or designated by the Biden administration has reviewed and approved the rule. In November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-carbon dioxide GHG emissions, such as methane and nitrous oxide. These executive orders and policy priorities may result in the development of additional regulations or changes to existing regulations, certain of which could negatively impact our financial position, results of operations and cash flows. In addition, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will take to achieve its GHG emissions targets. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. In addition, several states and geographic regions in the United States have also adopted legislation and regulations regarding climate change-related matters, and additional legislation or regulation by these states and regions, U.S. federal agencies, including the Environmental Protection Agency (the "EPA"), and/or international agreements to which the United States may become a party could result in increased compliance costs for us and our customers. Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, administrative, civil or criminal fines or penalties or injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the responsibility and costs of environmental protection and safety and health compliance fundamental, manageable parts of our business. To date, we have been able to plan for and comply with environmental, safety and health laws and regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, as well as the increasing number of climate-related commitments by capital providers, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

Our operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the statutory pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill. For further discussion, see Item *1A. Risk Factors - We are subject to extensive governmental regulation, which can change and could adversely impact our business.*

Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies have continued to assess the potential impacts of hydraulic fracturing, which could spur further action toward federal, state and/or local legislation and regulation. Further restrictions of hydraulic fracturing could make it difficult or impossible to conduct our drilling and completion operations, and thereby reduce the amount of oil, natural gas and NGL that we are ultimately able to produce from our properties.

Certain of our U.S. natural gas and oil leases, primarily in our Powder River Basin operating area, are granted or approved by the federal government and administered by the Bureau of Land Management (BLM) or Bureau of Indian Affairs (BIA) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. A federal district court judge in Louisiana issued a nationwide preliminary injunction on June 15, 2021, effectively preventing the Biden Administration from implementing the pause of new oil and natural gas leases on federal lands and waters and forcing the lease sale. On November 26, 2021, the U.S. Department of the Interior released its “Report On The Federal Oil And Gas Leasing Program,” which assessed the current state of oil and gas leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase oil and gas leases. Recently, on January 27, 2022, a federal district court judge in Washington, DC vacated the results of the federal government’s Lease Sale 257, effectively canceling the sale, on the grounds that the federal government failed to consider foreign consumption of oil and natural gas from its greenhouse gas emissions analysis. These recent developments and the Biden Administration’s and certain federal courts’ focus on the climate change impacts of federal projects could result in significant changes to the federal oil and gas leasing program in the future. Restrictions surrounding onshore drilling, onshore federal lease availability, and restrictions on the ability to obtain required permits could have a material adverse impact on our operations.

Permitting activities on federal lands are also subject to frequent delays. Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

For further discussion, see Item *1A. Risk Factors - Oil and natural gas operations are uncertain and involve substantial costs and risks.*

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and natural gas industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Nevertheless, we are involved in title disputes from time to time that may result in litigation.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, we could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

We maintain a control of well insurance policy with a $50 million single well limit and a $100 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. We also carry a $250 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $50 million pollution liability insurance policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to our working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

We own an office complex in Oklahoma City and we own or lease various field offices in cities or towns in the areas where we conduct our operations.

Executive Officers

Michael A. Wichterich, *Executive Chairman and Director*

Michael A. (“Mike”) Wichterich, 53, has served as Executive Chair of Chesapeake's Board of Directors since October 2021. He previously served as Chair of the Board of Directors since February 2021, and as the Company's Interim Chief Executive Officer from April 2021 to October 2021. Mr. Wichterich is Founder and Chief Executive Officer of Three Rivers Operating Company LLC, a private exploration and production company with a focus in the Permian Basin. Prior to founding Three Rivers Operating, Mr. Wichterich served as the Chief Financial Officer of Texas American Resources, New Braunfels Utilities and Mariner Energy. Additionally, Mr. Wichterich began his career with PricewaterhouseCoopers in its energy auditing practice. Mr. Wichterich also serves as a board member of Grizzly Energy. He earned a B.B.A. from the University of Texas.

Domenic J. Dell'Osso, Jr., *President, Chief Executive Officer and Director*

Domenic J. (“Nick”) Dell'Osso, Jr., 45, has served as President and Chief Executive Officer since October 2021. Prior to being named as CEO, Mr. Dell’Osso served as our Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as our Vice President – Finance and Chief Financial Officer of our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010. Before joining Chesapeake, Mr. Dell’Osso was an energy investment banker with Jefferies & Co. from 2006 to 2008 and Banc of America Securities from 2004 to 2006. Mr. Dell’Osso graduated from Boston College in 1998 and from the University of Texas at Austin in 2003.

Mohit Singh, ***Executive Vice President and Chief Financial Officer***

Mohit Singh, 44, was appointed Executive Vice President and Chief Financial Officer in December 2021. For the last six years, Mr. Singh has served on the executive leadership team at BPX Energy, the United States onshore subsidiary of BP (NYSE: BP). He most recently led the M&A, corporate land and reserves functions, having previously served as Head of Business Development and Exploration and as Senior Vice President – North Business Unit. Prior to joining BPX, Mr. Singh worked as an investment banker focused on oil and gas transactions for RBC Capital Markets and Goldman Sachs. A chemical engineer by training, he began his career at Shell Exploration & Production Company where he held business planning, reservoir engineering and research engineering roles of increasing importance. Mr. Singh earned a PhD in Chemical Engineering from the University of Houston, an MBA from the University of Texas and a BTech in Chemical Engineering from the Indian Institute of Technology.

Josh Viets, ***Executive Vice President and Chief Operating Officer***

Josh Viets, 43, was appointed Executive Vice President and Chief Operating Officer in February 2022. For the last 20 years, Mr. Viets has worked in operational positions of increasing importance at ConocoPhillips Company (NYSE: COP). He most recently served as Vice President, Delaware Basin and previously held leadership positions in operations, engineering, subsurface, and capital project across the ConocoPhillips portfolio. Mr. Viets earned a Bachelor of Science in Petroleum Engineering from Colorado School of Mines in 2001.

Benjamin E. Russ, ***Executive Vice President - General Counsel and Corporate Secretary***

Benjamin E. ("Ben") Russ, 47, was appointed Executive Vice President – General Counsel and Corporate Secretary in June 2021. Prior to that time, he served as Associate General Counsel – Corporate from May 2014 to June 2021; Division Counsel/Senior Division Counsel managing day-to-day legal matters in the Barnett, East Texas and Louisiana from July 2010 to May 2014; and Attorney/Senior Attorney managing litigation in Louisiana from September 2008 to July 2010. Before joining Chesapeake, Mr. Russ worked at Gulfport Energy Corporation serving as Assistant General Counsel from 2005 to 2006 and General Counsel from 2006 to 2008. Prior to Gulfport, he was an associate at the McKinney & Stringer, P.C. Mr. Russ received a B.S. in Finance from Oklahoma State University in 1996 and a J.D. from Oklahoma City University in 2004.

Human Capital Resources

One Team. One Chesapeake.

Our “One CHK” culture and company core values promote an inclusive, diverse and productive workplace. Working as One CHK defines Chesapeake’s culture and unites our team to achieve shared goals for the benefit of our stakeholders. It is a culture of accountability where innovation and collaboration help us achieve sustainable operational success. We had approximately 1,300 employees as of February 21, 2022.

Our Culture, Our Core Values

At Chesapeake, our employees are driven to create value every day in a safe and responsible manner. Our core values are the foundation of our culture and the driving force behind our goal to achieve ESG excellence. Serving as the lens through which we evaluate every business decision, our commitment to these values, in both words and actions builds a stronger, healthier Chesapeake, benefiting all our stakeholders. Our core values are:

- Integrity and Trust
- Respect
- Transparency and Open Communication
- Commercial Focus
- Change Leadership

Celebrating Inclusion and Diversity

We are committed to inclusion and diversity. We proactively embrace our diversity of people, thoughts and talents, and combine these strengths to pursue results and meaningful change for our company, employees and stakeholders, and we provide education and training for our employees on topics related to inclusion and diversity.

In 2019, Chesapeake joined a coalition of companies pledging to advance diversity and inclusion in the workplace. On February 9, 2021, we formed a board committee dedicated to ESG oversight, including our inclusion and diversity efforts. Two of the seven members of our Board of Directors are considered diverse, including one female and one “underrepresented minority” (as defined in Nasdaq’s newly proposed listing rule). Chesapeake cultivates a workplace in which diverse perspectives are welcomed and respected and where employees feel encouraged to discuss diversity and inclusion.

Stewards of Our Environment

Chesapeake is committed to protecting our country’s natural resources and reducing our environmental footprint. We have strict standards for environmental stewardship and a culture of environmental excellence among our employees and business partners. We recognize that ownership and accountability are key to helping ensure our work sites are safe and protective of the environment.

Our path to leading a responsible energy future begins with our goal to achieve net-zero direct greenhouse gas emissions by 2035. To meet this challenge, we have set meaningful initial steps including:

- Eliminating routine flaring from all new wells completed from 2021 forward, and enterprise-wide by 2025;
- Reducing our methane intensity to 0.09% by 2025 (achieved 0.08% in 2021); and
- Reducing our GHG intensity to 5.5 by 2025 (achieved 5.0 in 2021).

Safety First Every Day

Safety is more than a company metric, it is core to our commitment to leading a responsible energy future. We set and deliver strict safety standards, prioritizing the well-being of our employees and partners. Our safety culture is championed by our Board of Directors and executive leadership team, owned by every employee and contractor and managed by our Health, Safety, Environmental and Regulatory (HSER) team. Maintaining a safe work environment and promoting safe behaviors is a commitment that each of our employees own together. We hold each other accountable to keeping our sites, our co-workers and our contractors safe.

One program that reinforces this philosophy of personal responsibility is Stop Work Authority. Through Stop Work Authority, every employee and contractor has the right, responsibility and authority to stop work if conditions are unsafe or could cause harm to the environment. Creating an incident-free work environment starts with setting clear expectations among employees, contractors and suppliers regarding our safety standards, and working to empower and equip individuals with the skills necessary to promote safety in their areas of work. The foundation of our safety training efforts is our Stay Accident Free Every Day (S.A.F.E.) program, which encourages all workers on our locations to take personal responsibility for their safety and the safety of those around them. This behavior-based program addresses the activities that can often lead to safety incidents and encourages actions that create safe work sites and a safe corporate campus.

Every year our HSER team provides targeted trainings based on safety performance analysis, job functions and location specific factors. Our training program includes a mix of in-person and virtual training, with greater emphasis on in-person instruction and includes all employees. Job-specific learning paths aim to exceed regulatory requirements and ensure employees are holistically prepared to execute their job functions safely and responsibly.

Chesapeake's training philosophy values contractor training in the same manner as employees. We design contractor training to align as much as possible with employee training, encouraging synchronized knowledge sharing and understanding, critical to decreasing our cumulative incidents.

Ethical Business Conduct

Chesapeake works hard to maintain the confidence of our stakeholders. We earn this trust by acting in an ethical manner to protect our people, the environment and the communities where we operate. This starts by driving accountability through all levels of the company and having systems in place to uphold our high standards for conduct. Strong governance practices begin at the top providing our organization with clear guidelines to define standards for ethical behavior at every level. Each Chesapeake director or employee, regardless of position, must abide by Chesapeake's Code of Business Conduct (the "Code"), which is structured around our core values. Each year all employees must sign a Code certification confirming they have reviewed the Code and related policies, understand the high standards expected of them and will report actual or potential ethics concerns or Code violations.

Employee Wellness and Benefits

Supporting the individual well-being of our employees is foundational to our safety culture and success as a company. We champion healthy lifestyles and offer health resources. Across the company, employees are offered preventive programs and are encouraged to complete an annual screening for common health-related issues. We support our employees' and their families' health by offering full medical, dental, vision, prescription drug insurance for employees and their families, life insurance, short- and long-term disability coverage, and health savings and dependent care flexible spending accounts. We offer parental leave for the birth or adoption of a child, an adoption assistance program, alternate work schedules, a 401(k) savings plan with company match, flexible work hours, tuition reimbursement and access to a child development center and fitness center at market rates. Additionally, Chesapeake provides employees and their families access to a confidential Employee Assistance Program (EAP) which connects employees with trained counselors and other support professionals.

Item 1A. *Risk Factors*

There are numerous factors that affect our business and results of operations, many of which are beyond our control. The following is a description of factors that we consider to be material and that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, results of operations, cash flows, reserves and/or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Summary Risk Factors

Risks Related to our Emergence from Bankruptcy

- We recently emerged from bankruptcy, which may adversely affect our business and relationships.
- Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan and the transactions contemplated thereby.

Risks Related to Operating our Business

- Conservation measures and technological advances could reduce demand for natural gas and oil.
- Negative public perception regarding us or our industry could have an adverse effect on our operations.
- The oil and gas exploration and production industry is very competitive; some of our competitors have greater financial and other resources than we do, and there is competition to attract and retain talent, and competition over access to certain industry equipment.
- Oil, natural gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.
- The ongoing coronavirus (COVID-19) pandemic and related economic turmoil have affected and could continue to adversely affect our business, financial condition, results of operations and cash flows.
- If commodity prices fall or drilling efforts are unsuccessful, we may be required to record write downs of the carrying value of our oil and natural gas properties.
- Significant capital expenditures are required to replace our reserves and conduct our business.
- If we are not able to replace reserves, we may not be able to sustain production.
- The actual quantities of and future net revenues from our proved reserves may be less than our estimates.
- Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.
- Certain of our undeveloped properties are subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.
- Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.
- Oil and natural gas operations are uncertain and involve substantial costs and risks.
- Our ability to produce oil, natural gas and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.
- Risks related to potential acquisitions or dispositions may adversely affect our business.
- Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

- Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we or our third-party providers are unable to obtain and maintain adequate protection for our data, our business may be harmed.
- Our operations could be disrupted by natural or human causes beyond our control.

Financial Risks Related to our Business

- We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by industry conditions.
- Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.
- Changes in the method of determining the London Interbank Offered Rate (LIBOR), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

Risks Related to Recent and Pending Acquisitions

- The Chief Acquisition may not be completed. Failure to complete the Chief Acquisition could negatively impact the price of shares of our common stock, as well as our future business and financial results.
- The synergies attributable to the Vine Acquisition, or Chief Acquisition, if consummated, may vary from expectations, and we will be subject to business uncertainties for a period of time after the closing of the Vine Acquisition and Chief Acquisition, if consummated, which could adversely affect the combined company after these acquisitions. These uncertainties could include, but may not be limited to, loss of key personnel, retention of customer or supplier contracts or relationships, and litigation in connection with the Chief Acquisition.

Legal and Regulatory Risks

- We are subject to extensive governmental regulation, which can change and could adversely impact our business.
- Environmental and regulatory matters and related costs can be significant.
- Increasing attention to environmental, social and governance matters may impact our business, financial results or stock price.
- The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.
- Trading in our new common stock, additional issuances of new common stock, and certain other stock transactions could lead to a second, potentially more restrictive annual limitation on the utilization of our tax attributes reducing their ability to offset future taxable income, which may result in an increase to income tax liabilities.

General Risk Factors

- A deterioration in general economic, political, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.
- Military and other armed conflicts, including terrorist activities, could materially and adversely affect our business and results of operations.

Risks Related to our Emergence from Bankruptcy

We recently emerged from bankruptcy, which may adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our recent emergence from bankruptcy may adversely affect our business and relationships with customers, vendors, contractors or employees. Due to uncertainties, many risks exist, including the following:

- key vendors or other contract counterparties may terminate their relationships with us or require additional financial assurances or enhanced performance from us;
- our ability to renew existing contracts and compete for new business may be adversely affected;
- our ability to attract, motivate and/or retain key executives may be adversely affected; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan and the transactions contemplated thereby.

In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of the Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of 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 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. Actual results may vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

Risks Related to Operating our Business

Conservation measures and technological advances could reduce demand for natural gas and oil.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas and oil. The impact of the changing demand for natural gas and oil could adversely impact our earnings, cash flows and financial position.

Negative public perception regarding us or our industry could have an adverse effect on our operations.

Negative public perception regarding us or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to generally increased political pressure and regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, encourage capital providers to divest of their interests in us or our industry, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business. A change in control of national or local governments, including the U.S. presidential administration, Congress, state or local governments, and governments of other countries may also result in uncertainty regarding the degree to which there will be increased restrictions on oil and gas production activities, which could materially adversely affect our industry and our financial condition and results of operations.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult or costly for us to secure funding for exploration and production activities. Members of the investment community have also begun to screen companies such as ours for sustainability performance, including practices related to GHGs and climate change, before investing in our common units. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are less economically efficient or are not economically viable in order to improve our sustainability performance and to meet the specific requirements to perform services for certain customers.

The oil and gas exploration and production industry is very competitive; some of our competitors have greater financial and other resources than we do, and there is competition to attract and retain talent and competition over access to certain industry equipment.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing oil, natural gas or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address industry challenges more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively may be diminished. We also compete for the equipment required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield equipment and services, which could adversely affect our ability to execute our development plans on a timely basis and within budget.

Oil, natural gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, results of operations, profitability, liquidity, leverage ratio and ability to grow and invest in capital expenditures depend primarily upon the prices we receive for the oil, natural gas and NGL we sell. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, periods of low oil and natural gas prices may result in a reduction of the carrying value of our oil and natural gas properties due to recognizing impairments in proved and unproved properties.

Volatility in oil, natural gas and NGL prices may result from factors that are beyond our control, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- weather conditions;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns, such as the COVID-19 pandemic;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil, natural gas, liquefied natural gas and NGL;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and others to agree to and maintain oil price and production controls;
- increased use of competing energy products, including alternative energy sources;
- political instability or armed conflict in oil and natural gas producing regions;
- acts of terrorism; and
- domestic and global economic and political conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements. In addition, any prolonged period of lower prices could reduce the quantities of reserves that we may economically produce.

The ongoing COVID-19 pandemic and related economic turmoil have affected, and could continue to adversely affect, our business, financial condition, results of operations and cash flows.

The global spread of COVID-19 created significant volatility, uncertainty, and economic disruption during 2020 and 2021, and threatens to do the same in 2022. The ongoing COVID-19 pandemic has reached more than 200 countries and continues to present rapidly evolving economic and public health risks. The pandemic has adversely impacted the entire global economy, and there is considerable uncertainty regarding how long the pandemic and related market conditions will persist and the extent and duration of governmental and other measures implemented to try to slow the spread of the virus, such as quarantines, shelter-in-place orders, business and government shutdowns and restrictions on operations. In certain cases, states that had begun taking steps to reopen their economies experienced a subsequent surge in cases of COVID-19, causing these states to cease or dramatically scale back such reopening measures in some cases and reinstitute restrictions in others. Our precautionary measures and plans may not be effective in preventing future disruptions to our business. Moreover, future operations could be negatively affected if a significant number of our employees are quarantined as a result of exposure to the virus. In addition, actions by our customers and derivative contract counterparties in response to COVID-19 and its economic impacts, including potential non-performance or delays, may also have an adverse impact on our business.

Furthermore, the impact of the pandemic, including the initial resulting reduction in demand for oil and natural gas, coupled with the sharp decline in commodity prices following the announcement of price reductions and production increases in March 2020 by members of OPEC+ has led to significant global economic contraction generally and in our industry in particular. While an agreement to cut production has since been announced by OPEC+ and its allies, the supply and demand imbalance created by such price reductions and production increases, coupled with the impact of COVID-19, has continued to result in a significant downturn in the oil and gas industry. Although OPEC+ agreed in April 2020 to cut oil production and has extended such production cuts through

March 2021, crude oil prices have remained depressed as a result of the oversupply of oil, an increasingly utilized global storage network and the decrease in crude oil demand due to COVID-19. Oil and natural gas prices are expected to continue to be volatile as a result of the ongoing COVID-19 pandemic and as changes in oil and natural gas inventories, industry demand and national and economic performance are reported, and we cannot predict when prices will improve and stabilize. Due to numerous uncertainties, we cannot at this time predict the full impact that COVID-19 or the significant disruption and volatility currently being experienced in the oil and natural gas markets will have on our business, financial condition and results of operations.

The ultimate impact of COVID-19 will depend on future developments that cannot be anticipated, including, among others, the ultimate severity of the virus and its rapidly evolving and spreading variants, the consequences of governmental and other measures designed to mitigate the spread of the virus, the development and availability of treatments and vaccines and the extent to which these treatments and vaccines may remain effective as new strains of the virus emerge, the duration of the pandemic, any further actions taken by members of OPEC+, actions taken by governmental authorities, customers, suppliers and other third parties, workforce availability, and the timing and extent of any return to normal economic and operating conditions.

If commodity prices fall or drilling efforts are unsuccessful, we may be required to record write downs of the carrying value of our oil and natural gas properties.

We have been required to write down the carrying value of certain of our oil and natural gas properties in the past, and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur in the future when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, or due to the anticipated sale of properties.

The successful efforts method of accounting requires that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. A writedown constitutes a non-cash charge to earnings and does not impact cash or cash flows from operating activities; however, it reflects our long-term ability to recover an investment, reduces our reported earnings and increases certain leverage ratios. See *Impairment of Oil and Natural Gas Properties* included in Item 7 of this report for further information.

Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations, and to the extent that is not sufficient, borrowings under our revolving credit facility. Our ability to generate operating cash flow is subject to a number of risks and variables, such as the level of production from existing wells, prices of oil, natural gas and NGL, our success in developing and producing new reserves and the other risk factors discussed herein. Our forecasted 2022 capital expenditures, inclusive of capitalized interest, are $1.5 - $1.8 billion compared to our 2021 capital spending level of $746 million. Management continues to review operational plans for 2022 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL. If we are unable to fund our capital expenditures as planned, we could experience a curtailment of our exploration and development activity, a loss of properties and a decline in our oil, natural gas and NGL reserves.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. Thus, our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil, natural gas and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2021, approximately 41% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans for capital expenditures to convert PUDs into proved developed reserves, including approximately $2.7 billion during the next five years. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. If we choose not to develop our PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average oil and natural gas price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2021 present value is based on a $66.56 per bbl of oil price and a $3.60 per mcf of natural gas price, before considering basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for oil and natural gas, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We have acquired undeveloped properties that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive, or that we will recover all or any portion of our investment in such undeveloped properties 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 commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, federal restrictions on oil and gas leasing and permitting, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated if commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil, natural gas and NGL, costs associated with producing oil, natural gas and NGL and our ability to add reserves at an acceptable cost.

We rely to a significant extent on seismic data and other technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of undeveloped properties, or drilling a well, whether oil or natural gas is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

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

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, 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. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties.

Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

To manage our exposure to price volatility, we enter into oil, natural gas and NGL price derivative contracts. Our oil, natural gas and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our oil, natural gas and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if we believe the pricing environment for certain time periods is unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Most of our oil, natural gas and NGL derivative contracts are with counterparties under bilateral hedging arrangements. Under a majority of our arrangements, the collateral provided for our obligations is secured by the same hydrocarbon interests that secure our Exit Credit Facility. Our counterparties' obligations under the arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. Collateral requirements are dependent to a large extent on oil and natural gas prices.

Oil, natural gas and NGL derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements are required to secure their obligations to us under certain scenarios, if any of our counterparties were to default on their obligations to us under the derivative contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future cash flows being exposed to commodity price changes.

Oil and natural gas operations are uncertain and involve substantial costs and risks.

Our operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, natural gas and NGL can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. Although both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control;
- the mishandling or underground migration of fluids and chemicals;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained downstream markets;
- environmental hazards or liabilities;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations;
- shortages or delays in the availability of services or delivery of equipment; and
- unexpected or unforeseen changes in regulatory policy, and political or public opinion.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant damage to property and natural resources.

Our ability to produce oil, natural gas and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Development activities, particularly hydraulic fracturing, require the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. The imposition of environmental initiatives and regulations could further restrict our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of oil and natural gas.

Risks related to potential acquisitions or dispositions may adversely affect our business.

From time to time, we evaluate acquisitions and dispositions of assets, businesses and other investments. These transactions may not result in the anticipated benefits or efficiencies. In addition, acquisitions may be financed by borrowings, requiring us to incur more debt, or by the issuance of our common stock. Any such acquisition or disposition involves risks and we cannot assure you that:

- any acquisition will be successfully integrated into our operations and internal controls;
- the due diligence conducted prior to an acquisition will uncover situations that could result in financial or legal exposure, such as title defects and potential environmental and other liabilities;
- post-closing purchase price adjustments will be realized in our favor;
- our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating, operating expenses and costs will be accurate;
- any investment, acquisition, disposition or integration will not divert management resources from the operation of our business; and
- any investment, acquisition, or disposition or integration will not have a material adverse effect on our financial condition, results of operations, cash flows or reserves.

If any of these risks materialize, the benefits of such acquisition or disposition may not be fully realized, if at all, and our financial condition, results of operations, cash flows and reserves could be negatively impacted.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. We rely heavily on third parties to meet our oil, natural gas and NGL gathering needs. Capital constraints could limit the construction of new pipelines and gathering systems and the provision or expansion of trucking services by third parties. Until this new capacity is available, we may experience delays in producing and selling our oil, natural gas and NGL. In such event, we might have to shut in our wells while awaiting a pipeline connection or additional capacity, which would adversely affect our results of operations.

A portion of our oil, natural gas and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, 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 materially adversely affect our cash flow.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we or our third-party providers are unable to obtain and maintain adequate protection for our data, our business may be harmed.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. In addition, many third-party providers, such as vendors and others in the supply chain, directly or indirectly provide to us various products and services across an array of internal and external functions that enable us to conduct, monitor and/or protect our business, systems and data assets. In addition, in the ordinary course, we and our service providers collect, process, transmit, and store proprietary and confidential data, including personal information.

We have been the subject of cyber-attacks on our internal systems and through those of third parties in the past. As an energy company, we expect to continue to be a target for such attacks in the future. We are vulnerable to malicious attacks by third parties or insiders, social engineering and human error, as well as to bugs and other vulnerabilities that may exist in our third-party providers systems. Unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. If our information technology systems cease to function properly or our cybersecurity is breached (for example, due to ransomware), we could suffer disruptions to our normal operations, which may include disruptions to our drilling, completion, production and corporate functions. A cyber-attack involving our information systems and related infrastructure, or that of our business associates or third-party providers, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

Both the frequency and magnitude of cyberattacks is expected to increase and attackers are becoming more sophisticated. As a result, we may be unable to anticipate, detect or prevent future attacks, particularly as the methodologies utilized by attackers change frequently or are not recognized until launched, and we may be unable to investigate or remediate incidents because attackers are increasingly using techniques and tools designed to circumvent controls, to avoid detection, and to remove or obfuscate forensic evidence. Further, our increased reliance on remote access to our information systems as a result of the COVID-19 pandemic increases our exposure to potential cybersecurity breaches. As cyber-attacks continue to evolve, we may be required to spend significant additional resources to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks. In addition, new laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate costs as we collect and store personal data related to employees, royalty owners and other parties. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. For example, the California Consumer Privacy Act ("CCPA") was signed into law on June 28, 2018 and largely took effect on January 1, 2020. The CCPA, among other things, contains new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provides for statutory fines and penalties for certain data security breaches or other CCPA violations. At least fifteen other states have considered, and some have already enacted privacy laws like the CCPA.

Any losses, costs or liabilities directly or indirectly related to cyberattacks or similar incidents may not be covered by, or may exceed the coverage limits of, any or all of our insurance policies.

***Our operations could be disrupted by natural or human causes beyond our control*.**

Our operations are subject to disruption from natural or human causes beyond our control, including risks from extreme weather events, such as hurricanes, severe storms, floods, heat waves, and ambient temperature increases, as well as wildfires, war, accidents, civil unrest, political events, earthquakes, system failures, cyber threats, terrorist acts and epidemic or pandemic diseases, such as the COVID-19 pandemic, any of which could result in suspension of operations or harm to people, our assets or the natural environment.

It is difficult to predict with certainty the timing, frequency or severity of such events, any of which could have a material adverse effect on our results of operations or financial condition.

In addition, our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects and producing wells throughout the United States from this location, which could be disrupted if a catastrophic event, such as a tornado, power outage or act of terror, destroyed or severely damaged our headquarters. Any such catastrophic event could harm our ability to conduct normal operations and could adversely affect our business.

Financial Risks Related to our Business

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. In the past, low commodity prices have caused and may continue to cause lenders to increase the interest rates under upstream operators' credit facilities, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. Additionally, certain financial institutions have announced their intention to cease investment banking and corporate lending activities in the North American oil and gas sector or have established climate-related funding commitments that could have the effect of limiting their investment in us or our industry. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. Additionally, challenges in the economy have led and could further lead to reductions in the demand for oil and gas, or further reductions in the prices of oil and gas, or both, which could have a negative impact on our financial position, results of operations and cash flows.

Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our debt agreements impose operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- make investments or loans;
- create liens;
- consummate mergers and similar fundamental changes;
- make restricted payments;
- make investments in unrestricted subsidiaries;
- enter into transactions with affiliates; and
- use the proceeds of asset sales.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under certain of our debt agreements. The restrictions contained in the covenants could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or divestitures to engage in other business activities that would be in our interest.

Changes in the method of determining the London Interbank Offered Rate (LIBOR), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

Amounts drawn under certain of our debt instruments may bear interest at rates based on LIBOR. On July 27, 2017, the Financial Conduct Authority in the United Kingdom (the "FCA") announced that it would phase out LIBOR as a benchmark by the end of 2021. The publication of USD LIBOR will cease after June 30, 2023, and the FCA confirmed that use of USD LIBOR will not be permitted in most new contracts after December 31, 2021. The Credit Agreement adopts the hardwire approach for LIBOR replacement which provides that Term SOFR (or Daily Simple SOFR, to the extent Term SOFR is unavailable) will be used in the event of LIBOR cessation or upon an election to early opt-in, once SOFR becomes available. The Credit Agreement also provides that in the event that SOFR is not available at the time of LIBOR cessation, the borrower and agent must agree on a successor rate subject to negative consent rights of the lenders. We are currently evaluating the impact of the potential replacement of the LIBOR interest rate. In addition, the overall financial markets may be disrupted as a result of the phase-out or replacement of LIBOR. Uncertainty as to the nature of such potential phase-out and alternative reference rates or disruption in the financial market could have a material adverse effect on our financial condition, results of operations and cash flows.

Risks Related to Recent and Pending Acquisitions

The Chief Acquisition may not be completed. Failure to complete the Chief Acquisition could negatively impact the price of shares of our common stock, as well as our future business and financial results.

The Chief Acquisition is subject to a number of conditions that must be satisfied or, to the extent permitted by applicable law, waived, prior to the completion of the merger. These conditions to the completion of the Chief Acquisition, some of which are beyond our control, may not be satisfied or waived in a timely manner or at all, and, accordingly, the Chief Acquisition may be delayed or may not be completed.

If the Chief Acquisition is not completed for any reason, our ongoing business, financial condition and financial results may be adversely affected. Without realizing any of the benefits of having completed the transactions, we will be subject to a number of risks, including the following:

- we may be required to pay certain costs relating to the Chief Acquisition, which are substantial, such as legal, accounting, financial advisory and printing fees, whether or not the transactions are completed;
- time and resources committed by our management to matters relating to the Chief Acquisition could otherwise have been devoted to pursuing other beneficial opportunities;
- we may experience negative reactions from financial markets, including negative impacts on the price of our common stock, including to the extent that the current market price reflects a market assumption that the Chief Acquisition will be completed;
- we may experience negative reactions from employees, customers or vendors; and
- we may not have been able to take certain actions during the pendency of the Chief Acquisition that would have benefitted us as an independent company and the opportunity to take such actions may no longer be available.

In addition, any delay in completing the Chief Acquisition may significantly reduce the synergies and other benefits that we expect that the combined company may achieve if the Chief Acquisition is completed within the expected timeframe.

Required regulatory approvals for the Chief Acquisition may not be received, may take longer than expected to be received, or may impose conditions that are not presently anticipated or cannot be met.

Completion of the Chief Acquisition is conditioned upon the expiration or termination of any waiting period applicable to the merger under the HSR Act. Although each party has agreed to use its reasonable best efforts to ensure the prompt expiration or termination of any applicable waiting period under the HSR Act and to respond to and comply with any request for information from any governmental entity charged with enforcing, applying, administering or investigating the HSR Act or any other antitrust laws, there can be no assurance that HSR clearance will be obtained and that the other conditions to completing the Chief Acquisition will be satisfied. In addition, the governmental authorities from which the regulatory approvals are required may impose conditions on the completion of the Chief Acquisition or require changes to the terms of the Chief Acquisition. We cannot provide any assurance that these approvals will be obtained or that there will not be any adverse consequences to our business resulting from the failure to obtain these governmental approvals or from conditions that could be imposed in connection with obtaining these governmental approvals.

Completion of the Chief Acquisition is also conditioned upon the authorization for listing of our common stock to be issued in connection with the Chief Acquisition on the Nasdaq Global Select Market, or such other Nasdaq market on which our shares of common stock are then listed. There can be no assurance that such approval will be obtained or that the other conditions to completing the Chief Acquisition will be satisfied.

Such conditions or changes and the process of obtaining regulatory approvals could have the effect of delaying or impeding consummation of the Chief Acquisition or of imposing additional costs or limitations on us following completion of the Chief Acquisition, any of which might have an adverse effect on us following completion of the Chief Acquisition and may diminish the anticipated benefits of the Chief Acquisition.

The synergies attributable to the Vine Acquisition, or Chief Acquisition, if consummated, may vary from expectations.

We may fail to realize the anticipated benefits and synergies expected from the Vine Acquisition, or Chief Acquisition, if consummated, which could adversely affect our business, financial condition and results of operations. The success of these acquisitions will depend, in significant part, on our ability to successfully integrate the acquired businesses, grow the revenue of the combined company and realize the anticipated strategic benefits and synergies from the combinations, such as operational and financial scale, and increased Free Cash Flow. However, achieving these goals requires, among other things, realization of the targeted cost synergies expected from these acquisitions. The growth and the anticipated benefits of the acquisitions may not be realized fully or at all, or may take longer to realize than expected. Actual operating, technological, strategic and revenue opportunities, if achieved at all, may be less significant than expected or may take longer to achieve than anticipated. If we are not able to achieve these objectives and realize the anticipated benefits and synergies expected from the Vine Acquisition, or Chief Acquisition, if consummated, within the anticipated timing or at all, our business, financial condition and results of operations may be adversely affected.

We will be subject to business uncertainties for a period of time after the closing of the Vine Acquisition and Chief Acquisition, if consummated, which could adversely affect the combined company after these acquisitions.

Uncertainty about the effect of these acquisitions on employees, industry contacts and business partners may have an adverse effect on the combined company. These uncertainties may impair the combined company's ability to attract, retain and motivate key personnel for a period of time after the closing of these acquisitions and could cause industry contacts, business partners and others that deal with the combined company to seek to change their existing business relationships with the combined company.

Uncertainties associated with the Vine Acquisition and Chief Acquisition, if consummated, may cause a loss of management personnel and other key employees, which could adversely affect the future business and operations of the combined company.

The combined company's success after the Vine Acquisition and Chief Acquisition, if consummated, will depend in part upon the ability to retain key management personnel and other key employees of the Company, Vine and Chief. Current and prospective employees may experience uncertainty about their roles within the combined company following the Vine Acquisition, and Chief Acquisition, if consummated, which may have an adverse effect on the ability of the combined company to attract or retain key management and other key personnel. Accordingly, no assurance can be given that the combined company will achieve the same success attracting or retaining key management personnel and other key employees as the Company may have independently achieved prior to the Vine Acquisition and Chief Acquisition, if consummated.

We have incurred and will continue to incur significant transaction and acquisition-related costs in connection with the Vine Acquisition and Chief Acquisition, which may be in excess of our expectations.

We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the Vine Acquisition and Chief Acquisition and combining the operations of the acquired entities and achieving desired synergies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the Vine Acquisition and Chief Acquisition and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs and filing fees.

We will also incur transaction fees and costs related to the integration of the companies, which may be substantial. Moreover, we may incur additional unanticipated expenses in connection with the Vine Acquisition and the integration, including costs associated with any stockholder litigation related to the Vine Acquisition. Although we expect that the elimination of duplicative costs as well as the realization of other efficiencies related to the integration of the businesses should offset integration-related costs over time, this net benefit may not be achieved in the near term, or at all. Similar risks regarding the integration of Chief may arise if the Chief Acquisition is completed.

The costs described above, as well as other unanticipated costs and expenses, could have a material adverse effect on our financial condition and results of operations.

Completion of the Chief Acquisition may trigger change in control or other provisions in certain agreements to which Chief or its subsidiaries is a party.

The completion of the Chief Acquisition may trigger change in control or other provisions in certain agreements to which Chief or its subsidiaries is a party. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under such agreements, potentially terminating the agreement or seeking monetary damages. Additionally, even if we are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to the combined company.

Lawsuits may be filed against the Company Chief and their respective affiliates in connection with the Chief Acquisition. An adverse ruling could result in substantial costs and could result in an injunction preventing the completion of the Chief Acquisition.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other business combination agreements like those related to the Chief Acquisition. Even if any of the lawsuits which have been filed and may be filed are without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition.

One of the conditions to the closing of the Chief Acquisition is that no injunction by any governmental entity has been entered and continues to be in effect and no law has been adopted, in either case, that prohibits the closing of the Chief Acquisition. Consequently, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Chief Acquisition, that injunction may delay or prevent the Chief Acquisition from being completed within the expected timeframe, or at all, which may adversely affect our business, financial position and results of operations.

Additionally, there can be no assurance that any of the defendants in any potential future lawsuits will be successful in the outcome of such lawsuits. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect our business, financial condition, results of operations and cash flows.

Our integration of the acquired businesses into the Company may not be as successful as anticipated, and we may not achieve the intended benefits or do so within the intended timeframes.

The Vine Acquisition and Chief Acquisition, if consummated, involve numerous operational, strategic, financial, accounting, legal, tax and other risks, potential liabilities associated with the acquired businesses, and uncertainties related to design, operation and integration of the acquired businesses' internal control over financial reporting. Difficulties in integrating the acquired businesses into the Company may result in the acquired businesses performing differently than expected, operational challenges, or the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate the acquired businesses into the Company in a manner that permits the Company to achieve the full revenue and cost savings anticipated from the Vine Acquisition and Chief Acquisition, if consummated;
- complexities associated with managing the larger, more complex integrated business;
- not realizing anticipated operating synergies;
- integrating personnel from different entities and the loss of key employees;

- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the Vine Acquisition or Chief Acquisition, if consummated;
- integrating relationships with industry contacts and business partners;
- performance shortfalls as a result of the diversion of management's attention caused by completing the acquisitions and the integration process; and
- the disruption of, or the loss of momentum in, ongoing business or inconsistencies in standards, controls, procedures and policies.

Additionally, the success of the Vine Acquisition and Chief Acquisition, if consummated, will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining the acquired businesses, including operational and other synergies that we believe the combined company will achieve. The anticipated benefits and cost savings of the Vine Acquisition and Chief Acquisition, if consummated, may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that we do not currently foresee.

Our results may suffer if we do not effectively manage our expanded operations following the Vine Acquisition and Chief Acquisition, if consummated.

The success of the Vine Acquisition and Chief Acquisition, if consummated, will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining the acquired businesses, including the need to integrate the operations and businesses of the acquired entities into our existing business in an efficient and timely manner, to combine systems and management controls and to integrate relationships with customers, vendors, industry contacts and business partners.

The anticipated benefits and cost savings of the Vine Acquisition and Chief Acquisition, if consummated, may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that we do not currently foresee. Some of the assumptions that we have made, such as the achievement of operating synergies, may not be realized. There could also be unknown liabilities and unforeseen expenses associated with the acquisitions that were not discovered in the due diligence review conducted prior to entering into each transaction.

The market price of our common stock may be affected by factors different from those that historically have affected the price of our common stock.

Our business differs from that of Vine in certain respects, and if consummated, the business acquired in the Chief Acquisition will also differ. Accordingly, the financial position or results of operations and/or cash flows of the combined company, as well as the market price of our common stock, may be affected by factors different from those currently affecting our financial position or results of operations and/or cash flows as an independent standalone company.

As a result of the Vine Acquisition, we have incorporated Vine's hedging activities into our business, and we may be exposed to additional commodity price risks arising from such hedges.

To mitigate its exposure to changes in commodity prices, Vine hedges natural gas prices from time to time, primarily through the use of certain derivative instruments. As a result of the Vine Acquisition, we assumed Vine's existing derivative instruments. Actual natural gas prices may differ from our expectations and, as a result, such derivative instruments may have a negative impact on our business, financial condition and results of operations.

The combined company may not be able to retain customers or suppliers, and customers or suppliers may seek to modify contractual obligations with the combined company, either of which could have an adverse effect on the combined company's business and operations. Third parties may terminate or alter existing contracts or relationships as a result of the Vine Acquisition or Chief Acquisition, if consummated.

As a result of the Vine Acquisition, or Chief Acquisition, if consummated, the combined company may experience impacts on relationships with customers and suppliers that may harm the combined company's business and results of operations. Certain customers or suppliers may seek to terminate or modify contractual obligations following the Vine Acquisition, or Chief Acquisition, if consummated, whether or not contractual rights are triggered as a result of such acquisition. There can be no guarantee that customers and suppliers will remain with or continue to have a relationship with the combined company or do so on the same or similar contractual terms following the acquisitions. If any customers or suppliers seek to terminate or modify contractual obligations or discontinue their relationships with the combined company, then the combined company's business and results of operations may be harmed. If the combined company's suppliers were to seek to terminate or modify an arrangement with the combined company, then the combined company may be unable to procure necessary supplies or services from other suppliers in a timely and efficient manner and on acceptable terms, or at all.

The acquired entities also have contracts with vendors, landlords, licensors and other business partners that may require consents from these other parties in connection with the Vine Acquisition or Chief Acquisition, if consummated. If these consents cannot be obtained, the combined company may suffer a loss of potential future revenue, incur costs and/or lose rights that may be material to the business of the combined company. Any such disruptions could limit the combined company's ability to achieve the anticipated benefits of the Vine Acquisition or Chief Acquisition, if consummated.

We are subject to risks related to health epidemics and pandemics, including the ongoing COVID-19 pandemic, and it is difficult to predict what effect, if any, this might have on the combined company after the Vine Acquisition and Chief Acquisition, if consummated.

We face various risks related to public health issues, including epidemics, pandemics and other outbreaks, including the ongoing COVID-19 pandemic. The actual and potential effects of COVID-19 include, but are not limited to, its impact on general economic conditions, trade and financing markets, changes in customer behavior and continuity in business operations, all of which create significant uncertainty. In addition, the pandemic has resulted in governmental authorities implementing significant and varied measures to contain the spread of COVID-19, including travel bans and restrictions, quarantines, shelter in place and stay at home orders and business shutdowns. Governmental authorities may enact additional restrictions, or tighten existing measures if COVID-19 continues to spread. These measures, as well as the COVID-19 pandemic broadly, may have a negative effect on the combined company after the Vine Acquisition and Chief Acquisition, if consummated, which effect will be difficult to predict.

Legal and Regulatory Risks

We are subject to extensive governmental regulation, which can change and could adversely impact our business.

Our operations are subject to extensive federal, state, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes, and tribal laws for a minor portion of our acreage. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. For example, on January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then, on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. On November 26, 2021, the U.S. Department of the Interior released its "Report On The Federal Oil And Gas Leasing Program," which assessed the current state of oil and gas leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase oil and gas leases. With respect to offshore oil and gas leases, challenges to President Biden's moratorium on leasing initially prevailed on June 15, 2021, when a federal court judge in Louisiana issued a nationwide preliminary injunction effectively preventing the Biden Administration from implementing the pause of new oil and natural gas leases on federal lands and waters and forcing the lease sale; however, on January 25, 2022, the U.S. District Court for the District of Columbia invalidated the lease sale, reasoning that the Biden Administration did not properly evaluate the climate change impacts of drilling in the Gulf of Mexico. Although we do not expect this ruling to impact the availability of onshore federal oil and gas lease sales, the Biden Administration's and certain federal courts' focus on the climate change impacts of federal projects could result in similar restrictions surrounding onshore drilling, onshore federal lease availability, and restrictions on the ability to obtain required permits, which could have a material adverse impact on our operations. In addition, we may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory developments could, among other things, restrict production levels, impose price controls, change environmental protection requirements with respect to the treatment of hazardous waste, air emissions, or water discharges, and increase taxes, royalties and other amounts payable to the government. Our operating and compliance costs could increase further if existing laws and regulations are revised, reinterpreted, or if new laws and regulations become applicable to our operations. We do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity. This is particularly true of changes related to pipeline safety, hydraulic fracturing and climate change, as discussed below.

Pipeline Safety. The pipeline assets in which we own interests are subject to stringent and complex regulations related to pipeline safety and integrity management. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as for certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect "high consequence areas." Recent PHMSA rules have also extended certain requirements for integrity assessments and leak detections beyond high consequence areas and impose a number of reporting and inspection requirements on regulated pipelines. Further, legislation funding PHMSA through 2023 requires the agency to engage in additional rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines. At this time, we cannot predict the cost of these requirements or other potential new or amended regulations, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and potential bans. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

Climate Change. Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce greenhouse gas emissions, such as carbon dioxide and methane. Policy makers at both the U.S. federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. The EPA and the BLM have issued regulations for the control of methane emissions, which also include leak detection and repair requirements, for the oil and gas industry and are likely to create additional regulations regarding such matters. For example, on November 15, 2021, the EPA proposed new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound (VOC) emissions from new and existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. The comment period for the proposed rule ended on January 31, 2022, and the EPA hopes to finalize it by the end of 2022. Once finalized, the regulations are likely to be subject to legal challenge, and will also need to be incorporated into the states' implementation plans, which will need to be approved by the EPA in individual rulemakings that could also be subject to legal challenge. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility. In addition, several states in which we operate have imposed limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of renewable energy standards and/or cap-and-trade and/or carbon tax programs. Renewable energy standards (also referred to as renewable portfolio standards) require electric utilities to provide a specified minimum percentage of electricity from eligible renewable resources, with potential increases to the required percentage over time. The development of a federal renewable energy standard, or the development of additional or more stringent renewable energy standards at the state level could reduce the demand for oil and gas, thereby adversely impacting our earnings, cash flows and financial position. A cap-and-trade program generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. A federal cap and trade program or expanded use of cap and trade programs at the state level could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. In addition, federal or state carbon taxes could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in an increasing number of financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this would make it more difficult and expensive to secure funding for exploration and production activities. Members of the investment community have also begun to screen companies such as ours for sustainability performance, including practices related to greenhouse gases and climate change, before investing in our common stock. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are not economically viable in order to improve our sustainability performance and to meet the specific requirements to perform services for certain customers.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity.

Environmental matters and related costs can be significant.

As an owner, lessee or operator of oil and gas properties, we are subject to various federal, state, tribal and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on us for the cost of remediating pollution that results from our operations. Environmental laws may impose strict, joint and several liability, and failure to comply with environmental laws and regulations can result in the imposition of administrative, civil or criminal fines and penalties, as well as injunctions limiting operations in affected areas. Any future costs associated with these matters are uncertain and will be governed by several factors, including future changes to regulatory requirements. Changes in or additions to public policy regarding the protection of the environment could have a significant impact on our operations and profitability.

Increasing attention to environmental, social and governance matters ("ESG") may impact our business, financial results or stock price.

In recent years, increasing attention has been given to corporate activities related to ESG matters in public discourse and the investment community. A number of advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through the investment and voting practices of investment advisers, public pension funds, activist investors, universities and other members of the investing community. These activities include increasing attention and demands for action related to climate change, advocating for changes to companies' boards of directors, and promoting the use of energy saving building materials. These activities may result in demand shifts for oil, natural gas and NGL. In addition, a failure to comply with investor or customer expectations and standards, which are evolving, or if we are perceived to not have responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, could cause reputational harm to our business, increase our risk of litigation, and could have a material adverse effect on our results of operations.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings systems for evaluating companies on their approach to ESG matters. These ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.

We are subject to taxation by various governmental authorities at the federal, state and local levels in the jurisdictions in which we do business. New legislation could be enacted by any of these governmental authorities making it more costly for us to produce oil and natural gas by increasing our tax burden. The Biden administration has called for changes to fiscal and tax policies which could lead to comprehensive tax reform. For example, federal legislation has been proposed that, if enacted, would impact federal income tax law applicable to the deduction of intangible drilling and development costs, percentage depletion and, the expensing of geological, geophysical, exploration and development costs. Other proposals changing federal income tax law could include a new corporate minimum tax based on book income, an increase to the corporate tax rate and the elimination of certain tax credits. If enacted, certain of these proposals could have a correlative impact on state income taxes. In addition, state and local authorities could enact new legislation that would increase various taxes such as sales, severance and ad valorem taxes as well as accelerate the collection of such taxes.

Trading in our new common stock, additional issuances of new common stock, and certain other stock transactions could lead to a second, potentially more restrictive annual limitation on the utilization of our tax attributes reducing their ability to offset future taxable income, which may result in an increase to income tax liabilities.

Upon emergence from bankruptcy on February 9, 2021, the Company experienced an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”), as all of the common stock and preferred stock of the Predecessor, or the old loss corporation, was canceled and replaced with new common stock of the Successor, or the new loss corporation (the “First Ownership Change”). As such, an annual limitation was computed based on the fair market value of the new equity immediately after emergence multiplied by the long-term tax-exempt rate in effect for the month of February 2021. This annual limitation will restrict the future utilization of our net operating loss (NOL) carryforwards, disallowed business interest carryforwards and tax credits that existed at the time of emergence.

Trading in our stock, additional issuances, and other stock transactions occurring subsequent to the emergence from Bankruptcy could lead to a second ownership change. In the event of a second ownership change, a second annual limitation would be determined at such time which could be more restrictive than the limitation of the First Ownership Change. Depending on the market conditions and the Company’s tax basis, a second ownership change may result in a net unrealized built-in loss. The annual limitation in such a case would additionally be applied to certain of the Company’s tax items other than just NOL carryforwards, disallowed business interest carryforwards and tax credits. For example, a portion of tax depreciation, depletion and amortization would also be subject to the annual limitation for a five-year period following the ownership change but only to the extent of the net unrealized built-in loss existing at the time of the second ownership change. Whether the new annual limitation would be more restrictive would depend on the value of our stock and the long-term tax-exempt rate in effect at the time of a second ownership change. If the new annual limitation is more restrictive it would apply to certain of the tax attributes existing at the time of the second ownership change including those remaining from the time of the First Ownership Change.

Further, should the Company be in a net unrealized built-in gain position at the time of a second ownership change, the proposed regulations issued on September 10, 2019, and on January 14, 2020, under Section 382(h) of the Code (the “Proposed Regulations”) would, if finalized in their present form, change the currently existing rules and limit the potential increases to the annual limitation amount for certain built-in gains existing at the time of an ownership change, (unless the transition relief provisions of the Proposed Regulations are applicable), thereby possibly reducing the ability to utilize tax attributes significantly.

Some states impose similar limitations on tax attribute utilization upon experiencing an ownership change.

General Risk Factors

A deterioration in general economic, political, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.

Historically, concerns about global economic growth and international political stability have had a significant impact on global financial markets and commodity prices. If the economic or political climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and materially adversely impact our results of operations, liquidity and financial condition.

Military and other armed conflicts, including terrorist activities, could materially and adversely affect our business and results of operations.

Military and other armed conflicts, terrorist attacks and the threat of both, whether domestic or foreign, could cause instability in the global financial and energy markets. Continued instability in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Information regarding our properties is included in Item 1. Business and in the Supplementary Information included in Item 8 of Part II of this report.

Item 3. *Legal Proceedings*

Chapter 11 Proceedings

Commencement of the Chapter 11 Cases automatically stayed the proceedings and actions against us that are referenced below, in addition to actions seeking to collect pre-petition indebtedness or to exercise control over the property of the Company's bankruptcy estates. The Plan in the Chapter 11 Cases, which became effective on February 9, 2021, provided for the treatment of claims against the Company's bankruptcy estates, including pre-petition liabilities that had not been satisfied or addressed during the Chapter 11 Cases. See Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information.

Litigation and Regulatory Proceedings

We were involved in a number of litigation and regulatory proceedings as of the Petition Date. Many of these proceedings were in early stages, and many of them sought damages and penalties, the amount of which is currently indeterminate. See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

Business Operations. We are involved in various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. The majority of these prepetition legal proceedings were settled during the Chapter 11 Cases or will be resolved in connection with the claims reconciliation process before the Bankruptcy Court. Any allowed claim related to such prepetition litigation will be treated in accordance with the Plan.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

We were recently dismissed from numerous lawsuits in Oklahoma alleging that we and other companies engaged in activities that have caused earthquakes. The lawsuits sought compensation for injury to real and personal property, diminution of property value, economic losses due to business interruption, interference with the use and enjoyment of property, annoyance and inconvenience, personal injury and emotional distress. In addition, they sought the reimbursement of insurance premiums and the award of punitive damages, attorneys' fees, costs, expenses and interest.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Item 4. *Mine Safety Disclosures*

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17CFR 229.104) is included in Exhibit 95.1 to this Form 10-K.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Common Stock

Upon our emergence from Chapter 11 bankruptcy on February 9, 2021, our then-authorized common stock and preferred stock were canceled and released under the Plan without receiving any recovery on account thereof. In accordance with the Plan confirmed by the Bankruptcy Court on February 9, 2021, we issued 97,097,081 shares of New Common Stock of the Successor, which are listed on the Nasdaq Stock Market LLC under the symbol CHK. In addition, on February 9, 2021, we issued 11,111,111 Class A Warrants, 12,345,679 Class B Warrants and 9,768,527 Class C Warrants, each of which are exercisable for one share of common stock per warrant at the initial exercise prices of $27.63, $32.13 and $36.18 per share, respectively. The warrants are immediately exercisable and will expire on February 9, 2026. For more information regarding our emergence from Chapter 11 bankruptcy and our Plan of Reorganization, see Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Dividends

We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021 of $0.34375 per share (an initial annual rate of $1.375 per share). In the third quarter of 2021, we announced an increase in the base quarterly dividend to $0.4375 per share (an annual rate of $1.75 per share) and announced our intent to adopt a variable return program that will result in the payment of an additional variable dividend, payable beginning in March 2022, equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. In January 2022, we announced our intent to increase the base dividend to $0.50 per share (an annual rate of $2.00 per share) beginning in the second quarter of 2022.

Repurchases of Equity Securities; Unregistered Sales of Equity Securities and Use of Proceeds

There were no repurchases or unregistered sales of our common stock during the quarter ended December 31, 2021.

On December 2, 2021, we announced that our Board of Directors authorized the repurchase of up to $1.0 billion in aggregate value of our common stock and/or warrants from time to time. The repurchase authorization permits repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, compliance with the Company's debt agreements and other appropriate factors. As of February 21, 2022, no repurchases had occurred.

Shareholders

As of February 21, 2022, there were approximately 146 holders of record of our common stock.

Item 6. *Selected Financial Data*

We have adopted the SEC's Disclosure Modernization Final Rule, effective February 10, 2021, for Item 301 of Regulation S-K. As such, Item 6 Selected Financial Data has not been provided.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with Item 8 of Part II of this report.

Introduction

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties to produce oil, natural gas and NGL from underground reservoirs. We own a large and geographically diverse portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 8,200 oil and natural gas wells. Upon closing of the Chief Acquisition and divestiture of our assets in the Powder River Basin in Wyoming, our portfolio will be focused on three operating areas including the natural gas resource plays in the Marcellus Shale in the northern Appalachian Basin in Pennsylvania ("Marcellus") and the Haynesville/Bossier Shales in northwestern Louisiana ("Haynesville") and the liquids-rich resource play in the Eagle Ford Shale in South Texas ("Eagle Ford").

Our strategy is to create shareholder value by generating sustainable Free Cash Flow from our oil and natural gas development and production activities. We continue to focus on improving margins through operating efficiencies and financial discipline and improving our Environmental, Social, and Governance ("ESG") performance. To accomplish these goals, we intend to allocate our human resources and capital expenditures to projects we believe offer the highest cash return on capital invested, to deploy leading drilling and completion technology throughout our portfolio, and to take advantage of acquisition and divestiture opportunities to strengthen our portfolio. We also intend to continue to dedicate capital to projects that reduce the environmental impact of our oil and natural gas producing activities. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation and general and administrative) per barrel of oil equivalent production through operational efficiencies by, among other things, improving our production volumes from existing wells.

Leading a responsible energy future is foundational to Chesapeake's success. Our core values and culture demand we continuously evaluate the environmental impact of our operations and work diligently to improve our ESG performance across all facets of our Company. Our path to leading a responsible energy future begins with our initiative to achieve net-zero direct greenhouse gas emissions by 2035, which we announced in February 2021. To meet this challenge, we have set meaningful initial goals including:

- Eliminate routine flaring from all new wells completed from 2021 forward, and enterprise-wide by 2025;
- Reduce our methane intensity to 0.09% by 2025 (achieved 0.08% in 2021); and
- Reduce our GHG intensity to 5.5 by 2025 (achieved 5.0 in 2021).

In July 2021, we announced our plan to receive independent certification of our natural gas production under the MiQ methane standard and EO100 Standard for Responsible Energy Development. Certified natural gas was available in our Haynesville assets as of the end of 2021, and we expect it to be available in our legacy Marcellus assets by the end of the second quarter of 2022. The MiQ certification will provide a verified approach to tracking our commitment to reduce our methane intensity to 0.09% by 2025, as well as support our overall objective of achieving net-zero direct greenhouse gas emissions by 2035.

Our results of operations as reported in our consolidated financial statements for the 2021 Successor Period, 2021 Predecessor Period, 2020 Predecessor Period and 2019 Predecessor Period are in accordance with GAAP. Although GAAP requires that we report on our results for the periods January 1, 2021 through February 9, 2021 and February 10, 2021 through December 31, 2021 separately, management views our operating results for the year ended December 31, 2021 by combining the results of the 2021 Predecessor Period and the 2021 Successor Period because management believes such presentation provides the most meaningful comparison of our results to prior periods. We are not able to compare the 40 days from January 1, 2021 through February 9, 2021 operating results to any of the previous periods reported in the consolidated financial statements and do not believe reviewing this period in isolation would be useful in identifying any trends in, or reaching any conclusions regarding, our overall operating performance. We believe the key performance indicators such as operating revenues and expenses for the 2021 Successor Period combined with the 2021 Predecessor Period provide more meaningful comparisons to other periods and are useful in understanding operational trends. Additionally, there were no changes in policies between the periods, and any material impacts as a result of fresh start accounting were included within the discussion of these changes. These combined results do not comply with GAAP and have not been prepared as pro forma results under applicable regulations, but are presented because we believe they provide the most meaningful comparison of our results to prior periods.

Recent Developments

Vine Acquisition

On November 1, 2021, we completed our acquisition of Vine pursuant to a definitive agreement with Vine dated August 10, 2021. The transaction strengthens Chesapeake's competitive position, meaningfully increasing our Free Cash Flow outlook and deepening our inventory of premium natural gas locations, while preserving the strength of our balance sheet.

Chief Acquisition and Powder River Basin Divestiture

On January 25, 2022, we announced our planned Chief Acquisition and the planned divestiture of our Powder River Basin assets. These transactions, which are subject to certain customary closing conditions, including certain regulatory approvals, are expected to close in the first quarter of 2022. In conjunction with the Vine Acquisition, these transactions simplify and refocus our asset portfolio, concentrating on three operating areas and advancing our highest-return assets in the Marcellus and Haynesville gas basins.

Chief Executive Officer, Chief Financial Officer, and Chief Operating Officer

On April 27, 2021, we announced the departure of Doug Lawler from his positions as Chief Executive Officer and Director of Chesapeake, effective April 30, 2021. Michael A. Wichterich, the Chairman of our Board of Directors, served as Interim Chief Executive Officer while the Board of Directors conducted a search for a new Chief Executive Officer.

On October 11, 2021, we announced that the Board of Directors appointed Domenic "Nick" Dell'Osso Jr. as President and Chief Executive Officer and as member of the Board of Directors, effective October 11, 2021. Additionally, on October 11, 2021, the Board of Directors appointed Michael A. Wichterich, who resigned as Interim Chief Executive Officer upon the appointment of Mr. Dell'Osso, as Executive Chairman of the Company.

On November 30, 2021, we announced that the Board of Directors appointed Mohit Singh as Executive Vice President and Chief Financial Officer, effective December 6, 2021.

On January 25, 2022, we announced that the Board of Directors appointed Josh Viets as Executive Vice President and Chief Operating Officer, effective February 1, 2022.

Emergence from Bankruptcy

On the Petition Date, the Debtors filed the Chapter 11 Cases under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. On June 29, 2020, the Bankruptcy Court entered an order authorizing the joint administration of the Chapter 11 Cases under the caption *In re Chesapeake Energy Corporation*, Case No. 20-33233. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries (collectively, the "Non-Filing Entities") were not part of the bankruptcy filing. The Non-Filing Entities continued to operate in the ordinary course of business.

The Bankruptcy Court confirmed the Plan and the Debtors entered the Confirmation Order on January 16, 2021. The Debtors emerged from bankruptcy on the Effective Date. In connection with our exit from bankruptcy, we filed a registration statement with the SEC to facilitate future sales of our equity by certain holders of our New Common Stock and warrants. See Item 1 Business, Item 3 Legal Proceedings, Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities and Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of our Chapter 11 proceedings.

COVID-19 Pandemic and Impact on Global Demand for Oil and Natural Gas

The global spread of COVID-19, created, and continues to create, significant volatility, uncertainty, and economic disruption during 2020 through 2021. The pandemic has reached more than 200 countries and territories and has resulted in widespread adverse impacts on the global economy and on our customers and other parties with whom we have business relations. To date, we have experienced limited operational impacts as a result of COVID-19 or related governmental restrictions. While we cannot predict the full impact that COVID-19 or the related significant disruption and volatility in the oil and natural gas markets will have on our business, cash flows, liquidity, financial condition and results of operations, we believe demand is recovering and prices will continue to be positively impacted in the near term. For additional discussion regarding risks associated with the COVID-19 pandemic, see Item 1A Risk Factors in this report.

Liquidity and Capital Resources

Liquidity Overview

For the 2021 Successor Period, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations, and our primary uses of cash have been for the development of our oil and natural gas properties, acquisitions of additional oil and natural gas properties and return of value to shareholders through dividends. Historically, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations, borrowings under certain credit agreements and dispositions of non-core assets. Our ability to issue additional indebtedness, dispose of assets or access the capital markets was substantially limited during the Chapter 11 Cases and required court approval in most instances. Accordingly, our liquidity in the 2021 and 2020 Predecessor Periods depended mainly on cash generated from operations and available funds under certain credit agreements including the DIP Facility in the 2021 Predecessor Period and revolving credit facility in the 2020 Predecessor Period.

We believe we have emerged from the Chapter 11 Cases as a fundamentally stronger company, built to generate sustainable Free Cash Flow with a strengthened balance sheet, geographically diverse asset base and continuously improving ESG performance. As a result of the Chapter 11 Cases, we reduced our total indebtedness by $9.4 billion by issuing equity in a reorganized entity to the holders of our FLLO Term Loan, Second Lien Notes, unsecured notes and allowed general unsecured claimants.

We believe our cash flow from operations, cash on hand and borrowing capacity under the Exit Credit Facility, as discussed below, will provide sufficient liquidity during the next 12 months and the foreseeable future. As of December 31, 2021, we had $2.625 billion of liquidity available, including $905 million of cash on hand and $1.720 billion of aggregate unused borrowing capacity available under the Exit Credit Facility. As of December 31, 2021, we had no outstanding borrowings under our Exit Credit Facility – Tranche A Loans, and $221 million in borrowings under our Exit Credit Facility – Tranche B Loans. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of our debt obligations, including principal and carrying amounts of our senior notes.

Dividend

With our strong liquidity position, we initiated a new dividend strategy in 2021. We paid dividends of $119 million on our New Common Stock in the 2021 Successor Period. See Note 12 for further discussion.

On August 10, 2021, we announced a variable return program that will result in the payment of an additional dividend, payable beginning in March 2022, equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base dividend, multiplied by 50%. On February 23, 2022, we declared a quarterly dividend payable of $1.7675 per share, which will be paid on March 22, 2022 to stockholders of record at the close of business on March 7, 2022. The dividend consists of a base quarterly dividend in the amount of $0.4375 per share and a variable quarterly dividend in the amount of $1.33 per share. In January 2022, we announced our intent to increase the base quarterly dividend to $0.50 per share beginning in the second quarter of 2022.

The declaration and payment of any future dividend, whether fixed or variable, will remain at the full discretion of the Board and will depend on the Company's financial results, cash requirements, future prospects and other relevant factors. The Company's ability to pay dividends to its stockholders is restricted by (i) Oklahoma corporate law, (ii) its Certificate of Incorporation, (iii) the terms and provisions of its Credit Agreement and (iv) the terms and provisions of the indentures governing its 5.50% Senior Notes due 2026, 5.875% Senior Notes due 2029 and 6.75% senior notes due 2029.

Derivative and Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. We enter into various derivative instruments to mitigate a portion of our exposure to commodity price declines, but these transactions may also limit our cash flows in periods of rising commodity prices. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to better predict the total revenue we expect to receive. See Item 7A Quantitative and Qualitative Disclosures About Market Risk included in Part II of this report for further discussion on the impact of commodity price risk on our financial position.

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2021, our material contractual obligations include repayment of senior notes, outstanding borrowings and interest payment obligations under the Exit Credit Facility, derivative obligations, asset retirement obligations, lease obligations, undrawn letters of credit and various other commitments we enter into in the ordinary course of business that could result in future cash obligations. In addition, we have contractual commitments with midstream companies and pipeline carriers for future gathering, processing and transportation of oil, natural gas and NGL to move certain of our production to market. The estimated gross undiscounted future commitments under these agreements were approximately $3.83 billion as of December 31, 2021. As discussed above, we believe our existing sources of liquidity will be sufficient to fund our near and long-term contractual obligations. See Notes 6, 7, 9, 15 and 23 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Post-Emergence Debt

On the Effective Date, pursuant to the terms of the Plan, the Company, as borrower, entered into a reserve-based credit agreement (the "Credit Agreement") providing for the Exit Credit Facility which features an initial borrowing base of $2.5 billion. The borrowing base will be redetermined semiannually on or around May 1 and November 1 of each year. Our borrowing base was reaffirmed in October 2021, and the next scheduled redetermination will be on or about May 1, 2022. The aggregate initial elected commitments of the lenders under the Exit Credit Facility were $1.75 billion of revolving Tranche A Loans and $221 million of fully funded Tranche B Loans.

The Exit Credit Facility provides for a $200 million sublimit of the aggregate commitments that are available for the issuance of letters of credit. The Exit Credit Facility bears interest at the ABR (alternate base rate) or LIBOR, at our election, plus an applicable margin (ranging from 2.25–3.25% per annum for ABR loans and 3.25–4.25% per annum for LIBOR loans, subject to a 1.00% LIBOR floor), depending on the percentage of the borrowing base then being utilized. The Tranche A Loans mature 3 years after the Effective Date and the Tranche B Loans mature 4 years after the Effective Date. The Tranche B Loans can be repaid if no Tranche A Loans are outstanding.

On February 2, 2021, the Company issued $500 million aggregate principal amount of its 5.50% Senior Notes due 2026 (the “2026 Notes”) and $500 million aggregate principal amount of its 5.875% Senior Notes due 2029 (the “2029 Notes and, together with the 2026 Notes, the “Notes”). The offering of the Notes was part of a series of exit financing transactions undertaken in connection with the Debtors’ Chapter 11 Cases and meant to provide the exit financing originally intended to be provided by the Exit Term Loan Facility pursuant to the Commitment Letter.

Assumption and Repayment of Vine Debt

In conjunction with the Vine Acquisition, Vine’s Second Lien Term Loan was repaid and terminated for $163 million inclusive of a $13 million make whole premium with cash on hand, due to the agreement containing a change in control provision making the term loan callable upon closing. Vine’s reserve based loan facility, which had no borrowings as of November 1, 2021, was terminated at the time of the completion of the Vine Acquisition. Additionally, Vine’s 6.75% Senior Notes with a principal amount of $950 million, were assumed by the Company at the time of the completion of the Vine Acquisition.

Pending Acquisition and Divestiture

On January 24, 2022, we entered into a definitive agreement to acquire Chief and associated non-operated interests held by affiliates of Tug Hill, for $2.0 billion in cash and approximately 9.44 million common shares. On January 24, 2022, we also entered into an agreement to sell our Powder River Basin assets to Continental Resources, Inc. for approximately $450 million in cash. We currently expect to fund the Chief Acquisition with cash on hand, borrowings under our Exit Credit Facility and the proceeds from the planned Powder River Basin divestiture.

Capital Expenditures

For the year ending December 31, 2022, we currently expect to bring or have online approximately 190 to 220 gross wells across 11 to 14 rigs and plan to invest between approximately $1.5 – $1.8 billion in capital expenditures, approximately $150 – $200 million of which is contingent upon the closing of the proposed Chief Acquisition. We expect that approximately 75% of our 2022 capital expenditures will be directed toward our natural gas assets. We currently plan to fund our 2022 capital program through cash on hand, expected cash flow from our operations and borrowings under our Exit Credit Facility. We may alter or change our plans with respect to our capital program and expected capital expenditures based on developments in our business, our financial position, our industry or any of the markets in which we operate.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Successor and Predecessor Periods:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	**Period from January 1, 2021 through February 9, 2021**	**Year Ended December 31, 2020**	**Year Ended December 31, 2019**
Net cash provided by (used in) operating activities	$ 1,809	$ (21)	$ 1,164	$ 1,623
Proceeds from issuances of debt, net	—	1,000	—	1,563
Proceeds from issuance of common stock	—	600	—	—
Proceeds from warrant exercise	2	—	—	—
Proceeds from divestitures of property and equipment	13	—	150	136
Proceeds from pre-petition revolving credit facility borrowings, net	—	—	339	496
Total sources of cash and cash equivalents	$ 1,824	$ 1,579	$ 1,653	$ 3,818

Cash Flow from Operating Activities

Cash provided by operating activities was $1.809 billion, $1.164 billion and $1.623 billion in the 2021 Successor Period, 2020 Predecessor Period and 2019 Predecessor Period, respectively. Cash used in operating activities was $21 million for the 2021 Predecessor Period. The increase in the 2021 Successor Period is primarily the result of higher prices for the oil, natural gas and NGL we sold coupled with a decrease in cash interest and GP&T costs following our emergence from bankruptcy. The cash used in the 2021 Predecessor Period was primarily in connection with the payment of professional fees related to the Chapter 11 Cases. The decrease in the 2020 Predecessor Period is primarily the result of lower prices for the oil, natural gas and NGL we sold. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items, such as depreciation, depletion and amortization, certain impairments, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under *Results of Operations*.

Proceeds from Issuance of Common Stock and Senior Notes

In the 2021 Predecessor Period, we issued $500 million aggregate principal amount of 5.50% 2026 Notes and $500 million aggregate principal amount of 5.875% 2029 Notes for total proceeds of $1.0 billion. Additionally, upon emergence from Chapter 11, we issued 62,927,320 shares of New Common Stock in exchange for $600 million of cash, as agreed upon in the Plan. In the 2019 Predecessor Period we obtained a $1.5 billion term loan and issued $120 million of senior secured second lien notes for net proceeds of $1.563 billion See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Divestitures of Property and Equipment

In the 2021 Successor Period we divested certain non-core assets for approximately $13 million. In the 2020 Predecessor Period, we divested our Mid-Continent asset for $130 million and certain non-core assets for approximately $6 million. In the 2019 Predecessor Period, we divested certain non-core assets for approximately $130 million. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the Successor and Predecessor Periods:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Oil and Natural Gas Expenditures:				
Capital expenditures	$ 669	$ 66	$ 1,142	$ 2,263
Other Uses of Cash and Cash Equivalents:				
Business combination, net	194	—	—	353
Payments on Exit Credit Facility - Tranche A Loans, net	50	479	—	—
Payments on DIP Facility borrowings, net	—	1,179	—	—
Debt issuance and other financing costs	3	8	109	—
Cash paid to purchase debt	—	—	94	1,073
Cash paid for common stock dividends	119	—	—	—
Cash paid for preferred stock dividends	—	—	22	91
Other	1	—	13	36
Total other uses of cash and cash equivalents	367	1,666	238	1,553
Total uses of cash and cash equivalents	$ 1,036	$ 1,732	$ 1,380	$ 3,816

Capital Expenditures

Our drilling and completion costs decreased in the combined 2021 Successor and Predecessor Periods compared to the 2020 Predecessor Period primarily as a result of decreased drilling and completion activity mainly in our liquids-rich plays. Our drilling and completion costs decreased in the 2020 Predecessor Period compared to the 2019 Predecessor Period primarily as a result of decreased drilling and completion activity mainly in our liquids-rich plays. In the combined 2021 Successor and Predecessor Periods, our average operated rig count was 7 rigs and 121 spud wells, compared to an average operated rig count of 8 rigs and 167 spud wells in the 2020 Predecessor Period and 18 rigs and 333 spud wells in the 2019 Predecessor Period. We completed 127 operated wells in the combined 2021 Successor and Predecessor Periods compared to 188 in the 2020 Predecessor Period and 370 in the 2019 Predecessor Period.

Business Combination

In the 2021 Successor Period, we acquired Vine for approximately 18.7 million shares of our New Common Stock and $253 million cash, less $59 million of cash held by Vine as of the acquisition date. In the 2019 Predecessor Period, we acquired WildHorse for approximately 3.6 million reverse stock split adjusted shares of our Predecessor common stock and $381 million cash, less $28 million of cash held by WildHorse as of the acquisition date. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of these acquisitions.

Payments on DIP Facility Borrowings

On the Effective Date, the DIP Facility was terminated, and the holders of obligations under the DIP Facility received payment in full in cash; provided that to the extend such lender under the DIP Facility was also a lender under the Exit Credit Facility, such lender’s allowed DIP claims were first reduced dollar-for-dollar and satisfied by the amount of its Exit RBL Loans provided as of the Effective Date.

Debt Issuance and Other Financing Costs

In the 2020 Predecessor Period, we paid $109 million of one-time fees to lenders to establish our DIP Credit Facility and Exit Credit Facility.

Cash Paid to Purchase Debt

In the 2020 Predecessor Period, we repurchased approximately $160 million aggregate principal amount of our senior notes for $94 million. In the 2019 Predecessor Period, we repurchased $698 million aggregate principal amount of our BVL Senior Notes for $693 million and retired our BVL revolving credit facility for $1.028 billion. We also repaid upon maturity $380 million principal amount of our Floating Rate Senior Notes due April 2019.

Cash Paid for Common Stock Dividends

As part of our dividend program, we paid dividends of $119 million on our New Common Stock in the 2021 Successor Period. See Note 12 for further discussion.

Cash Paid for Preferred Stock Dividends

We paid dividends of $22 million and $91 million on our Predecessor preferred stock during the 2020 and 2019 Predecessor Periods, respectively. On April 17, 2020, we announced that we were suspending payment of dividends on each series of our outstanding convertible preferred stock. On the Effective Date of the Chapter 11 Cases, each holder of an equity interest in Chesapeake had such interest canceled, released, and extinguished without any distribution. See Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information about the Chapter 11 Cases.

Results of Operations

Year ended December 31, 2021 compared to the year ended December 31, 2020

Below is a discussion of changes in our results of operations for the combined 2021 Successor and Predecessor Periods compared to the 2020 Predecessor Period. A discussion of changes in our results of operations for the 2020 Predecessor Period compared to the 2019 Predecessor Period has been omitted from this Form 10-K, but may be found in *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2020 as filed with the SEC on March 1, 2021.

Oil, Natural Gas and NGL Production and Average Sales Prices

	Successor							
	Period from February 10, 2021 through December 31, 2021							
	Oil		Natural Gas		NGL		Total	
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	$/boe
Marcellus	—	—	1,296	3.25	—	—	216	19.52
Haynesville	—	—	750	4.10	—	—	125	24.57
Eagle Ford	60	69.25	137	4.02	19	29.76	101	51.91
Powder River Basin	9	67.90	53	4.33	3	40.00	21	46.09
Total	69	69.07	2,236	3.61	22	31.37	463	29.19

	Predecessor							
	Period from January 1, 2021 through February 9, 2021							
	Oil		Natural Gas		NGL		Total	
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	$/boe
Marcellus	—	—	1,233	2.42	—	—	206	14.49
Haynesville	—	—	543	2.44	—	—	90	14.62
Eagle Ford	74	53.37	165	2.57	18	23.94	120	40.27
Powder River Basin	10	51.96	61	2.92	4	34.31	24	34.25
Total	84	53.21	2,002	2.45	22	25.92	440	22.63

	Predecessor							
	Year Ended December 31, 2020							
	Oil		Natural Gas		NGL		Total	
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	$/boe
Marcellus	—	—	1,052	1.64	—	—	175	9.82
Haynesville	—	—	543	1.83	—	—	90	10.99
Eagle Ford	86	38.38	185	1.90	24	10.93	141	27.72
Powder River Basin	13	36.64	58	1.92	4	14.94	26	24.22
Mid-Continent	4	38.17	34	1.98	3	12.36	13	20.18
Total	103	38.16	1,872	1.73	31	11.55	445	16.84

Oil, Natural Gas and NGL Sales

	Successor							
	Period from February 10, 2021 through December 31, 2021							
	Oil		Natural Gas		NGL		Total	
Marcellus	$	—	$	1,370	$	—	$	1,370
Haynesville		—		998		—		998
Eagle Ford		1,354		179		179		1,712
Powder River Basin		202		75		44		321
Total oil, natural gas and NGL sales	$	1,556	$	2,622	$	223	$	4,401

	Predecessor							
	Period from January 1, 2021 through February 9, 2021							
	Oil		Natural Gas		NGL		Total	
Marcellus	$	—	$	119	$	—	$	119
Haynesville		—		53		—		53
Eagle Ford		159		17		17		193
Powder River Basin		20		7		6		33
Total oil, natural gas and NGL sales	$	179	$	196	$	23	$	398

	Non-GAAP Combined							
	Year Ended December 31, 2021							
	Oil		Natural Gas		NGL		Total	
Marcellus	$	—	$	1,489	$	—	$	1,489
Haynesville		—		1,051		—		1,051
Eagle Ford		1,513		196		196		1,905
Powder River Basin		222		82		50		354
Total oil, natural gas and NGL sales	$	1,735	$	2,818	$	246	$	4,799

	Predecessor							
	Year Ended December 31, 2020							
	Oil		Natural Gas		NGL		Total	
Marcellus	$	—	$	631	$	—	$	631
Haynesville		—		362		—		362
Eagle Ford		1,202		129		97		1,428
Powder River Basin		170		41		20		231
Mid-Continent		55		25		13		93
Total oil, natural gas and NGL sales	$	1,427	$	1,188	$	130	$	2,745

Oil, natural gas and NGL sales in the combined 2021 Successor and Predecessor Periods increased $2.054 billion compared to the 2020 Predecessor Period. The increase was primarily attributable to a $1.901 billion increase in revenues from higher average prices received. Additionally, increased volumes in Marcellus and Haynesville, partially offset by decreased volumes in Eagle Ford, Powder River Basin and Mid-Continent, following the divestiture of our Mid-Continent assets in 2020, resulted in a $153 million increase in revenues. See Note 10 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of oil, natural gas and NGL sales.

Production Expenses

	Successor		Predecessor		Non-GAAP Combined		Predecessor	
	Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021		Year Ended December 31, 2020	
		$/Boe		$/Boe		$/Boe		$/Boe
Marcellus	$ 34	0.49	$ 4	0.50	$ 38	0.49	$ 32	0.50
Haynesville	59	1.44	4	1.12	63	1.42	41	1.28
Eagle Ford	173	5.25	21	4.24	194	5.13	201	3.89
Powder River Basin	31	4.45	3	3.37	34	4.32	42	4.41
Mid-Continent	—	—	—	—	—	—	57	12.56
Total production expenses	$ 297	1.97	$ 32	1.80	$ 329	1.95	$ 373	2.29

Production expenses in the combined 2021 Successor and Predecessor Periods decreased $44 million as compared to the 2020 Predecessor Period. The decrease was primarily due to a $57 million reduction from the sale of Mid-Continent properties in the 2020 Predecessor Period, in combination with the effects of workforce reductions in late 2020 and early 2021. The decrease was partially offset by a $12 million increase related to the Vine Acquisition in the Haynesville operating area.

Gathering, Processing and Transportation Expenses

	Successor		Predecessor		Non-GAAP Combined		Predecessor	
	Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021		Year Ended December 31, 2020	
		$/Boe		$/Boe		$/Boe		$/Boe
Marcellus	$ 287	4.09	$ 34	4.17	$ 321	4.10	$ 292	4.55
Haynesville	118	2.91	11	2.93	129	2.91	188	5.69
Eagle Ford	290	8.79	45	9.32	335	8.85	475	9.23
Powder River Basin	85	12.20	12	12.53	97	12.24	100	10.52
Mid-Continent	—	—	—	—	—	—	27	5.76
Total gathering, processing and transportation expenses	$ 780	5.17	$ 102	5.78	$ 882	5.24	$ 1,082	6.64

Gathering, processing and transportation expenses in the combined 2021 Successor and Predecessor Periods decreased $200 million as compared to the 2020 Predecessor Period. Haynesville decreased $84 million as a result of contract negotiations in the Chapter 11 Cases, partially offset by a $25 million increase associated with Vine acquired wells. Eagle Ford decreased $140 million primarily as a result of reduced production as well as contract negotiations in the Chapter 11 Cases. Additionally, the sale of Mid-Continent properties in 2020 resulted in a $27 million reduction. These decreases were partially offset by a $29 million increase in Marcellus primarily due to increased production.

Severance and Ad Valorem Taxes

	Successor		Predecessor		Non-GAAP Combined		Predecessor	
	Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021		Year Ended December 31, 2020	
		$/Boe		$/Boe		$/Boe		$/Boe
Marcellus	$ 9	0.12	$ 1	0.07	$ 10	0.12	$ 6	0.09
Haynesville	22	0.55	2	0.54	24	0.55	23	0.69
Eagle Ford	96	2.91	13	2.69	109	2.88	92	1.79
Powder River Basin	31	4.48	2	2.88	33	4.29	23	2.41
Mid-Continent	—	—	—	—	—	—	5	1.16
Total severance and ad valorem taxes	$ 158	1.05	$ 18	1.03	$ 176	1.05	$ 149	0.91

Severance and ad valorem taxes in the combined 2021 Successor and Predecessor Periods increased $27 million as compared to the 2020 Predecessor Period. The severance tax increase of $23 million was primarily driven by increased revenue as a result of improved pricing.

Gross Margin by Operating Area

The table below presents the gross margin for each of our operating areas. Gross margin by operating area is defined as oil, natural gas and NGL sales less production expenses, gathering, processing and transportation expenses, and severance and ad valorem taxes.

	Successor		Predecessor		Non-GAAP Combined		Predecessor	
	Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021		Year Ended December 31, 2020	
		$/Boe		$/Boe		$/Boe		$/Boe
Marcellus	$ 1,040	14.82	$ 80	9.75	$ 1,120	14.28	$ 301	4.68
Haynesville	799	19.67	36	10.03	835	18.88	110	3.33
Eagle Ford	1,153	34.96	114	24.02	1,267	33.56	660	12.81
Powder River Basin	174	24.96	16	15.47	190	23.81	66	6.88
Mid-Continent	—	—	—	—	—	—	4	0.70
Gross margin by operating area	$ 3,166	21.00	$ 246	14.02	$ 3,412	20.27	$ 1,141	7.00

Oil and Natural Gas Derivatives

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Oil derivatives – realized gains (losses)	$ (453)	$ (19)	$ 694
Oil derivatives – unrealized losses	(29)	(190)	(140)
Total gains (losses) on oil derivatives	(482)	(209)	554
Natural gas derivatives – realized gains (losses)	(715)	6	161
Natural gas derivatives – unrealized gains (losses)	70	(179)	(119)
Total gains (losses) on natural gas derivatives	(645)	(173)	42
Total gains (losses) on oil and natural gas derivatives	$ (1,127)	$ (382)	$ 596

See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of our derivative activity.

Marketing Revenues and Expenses

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Marketing revenues	$ 2,263	$ 239	$ 1,869
Marketing expenses	2,257	237	1,889
Marketing margin	$ 6	$ 2	$ (20)

Marketing revenues and expenses increased in the 2021 Successor Period as a result of increased oil, natural gas and NGL prices received in our marketing operations.

Exploration Expense

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Impairments of unproved properties	$ 1	$ 2	$ 411
Dry hole expense	1	—	7
Geological and geophysical expense and other	5	—	9
Total exploration expense	$ 7	$ 2	$ 427

The 2020 Predecessor Period exploration expense is the result of non-cash impairment charges in unproved properties, primarily in our Eagle Ford, Haynesville, Powder River Basin and Mid-Continent operating areas. See Note 20 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

General and Administrative Expenses

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Gross compensation and benefits	$ 231	$ 32	$ 383
Non-labor	86	12	195
Allocations and reimbursements	(220)	(23)	(311)
Total general and administrative expenses, net	$ 97	$ 21	$ 267
General and administrative expenses, net per Boe	$ 0.64	$ 1.19	$ 1.63

Compensation and benefits before reimbursements and allocations during the combined 2021 Successor and Predecessor Periods decreased $120 million compared to the 2020 Predecessor Period due to reductions in workforce in the 2020 and 2021 Predecessor Periods. Non-labor before reimbursements and allocations during the combined 2021 Successor and Predecessor Periods decreased $97 million compared to the 2020 Predecessor Period due to cost reduction initiatives for professional services as well as $43 million in fees for legal, financial and restructuring advisors incurred in preparation for the Chapter 11 Cases in the 2020 Predecessor Period. The decrease in allocations and reimbursements during the combined 2021 Successor and Predecessor Periods compared to the 2020 Predecessor Period was the result of reduced drilling, staffing reductions and the sale of Mid-Continent properties in 2020.

Separation and Other Termination Costs

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Separation and other termination costs	$ 11	$ 22	$ 44

Separation and other termination costs relate to one-time termination benefits for certain employees.

Depreciation, Depletion and Amortization

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Depreciation, depletion and amortization	$ 919	$ 72	$ 1,097
Depreciation, depletion and amortization per Boe	$ 6.10	$ 4.11	$ 6.72

The absolute and per unit decrease in depreciation, depletion and amortization for the 2021 Successor Period compared to the 2020 Predecessor Period was primarily the result of the revaluation of the depletable asset base occurring in connection with our emergence from bankruptcy. Fresh start accounting requires that new fair values be established for our assets as of the Effective Date. See Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Impairments

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Impairments of proved oil and natural gas properties	$ —	$ —	$ 8,446
Impairments of other fixed assets and other	1	—	89
Total impairments	$ 1	$ —	$ 8,535

In the 2020 Predecessor Period, we recorded impairments of proved oil and natural gas properties related to Eagle Ford, Powder River Basin, Mid-Continent and other non-core assets, all of which were due to lower forecasted commodity prices. Additionally, in the 2020 Predecessor Period, we recorded a $76 million impairment of our sand mine assets that support our Eagle Ford operating area for the difference between fair value and the carrying value of the assets as well as a $13 million impairment of compressor inventory due to a lack of a current market for compressors. See Note 19 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Other Operating Expense (Income), Net

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Other operating expense (income), net	$ 84	$ (12)	$ 80

In the 2021 Successor Period we recognized approximately $59 million of costs related to our acquisition of Vine, which included consulting fees, financial advisory fees and legal fees. Additionally, we recognized approximately $36 million of severance expense as a result of the Vine Acquisition, which included $15 million of cash severance and $21 million of non-cash severance, primarily related to the issuance of New Common Stock for the acceleration of certain Vine restricted stock unit awards. A majority of Vine executives and employees were terminated on the date the Vine Acquisition was completed. These executives and employees were entitled to severance benefits in accordance with existing employment agreements. In the 2020 Predecessor Period, we terminated certain gathering, processing and transportation contracts and recognized a non-recurring $80 million expense related to the contract terminations, $9 million expense related to the impairment of sand mine inventory and $42 million of other operating expense primarily related to royalty settlements and other legal matters, partially offset by $51 million of income from the amortization of VPP deferred revenue. In the 2020 Predecessor Period, we sold the assets related to our remaining volumetric production payment and extinguished the liability related to the production volume delivery obligation.

Interest Expense

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Interest expense on debt	$ 79	$ 11	$ 402
Amortization of premium, discount, issuance costs and other	5	—	(56)
Capitalized interest	(11)	—	(15)
Total interest expense	$ 73	$ 11	$ 331

The decrease in total interest expense in the 2021 Successor Period compared to the 2020 Predecessor Period resulted from the decrease in outstanding debt obligations between periods. Upon emergence from the Chapter 11 Cases, all outstanding obligations under our Predecessor senior notes and term loan were canceled in exchange for shares of New Common Stock and Warrants. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Other Income (Expense)

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Other income (expense)	$ 31	$ 2	$ (4)

In the 2021 Successor Period, we recorded a gain of $22 million for a refund from a midstream provider.

Reorganization Items, Net

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Gains on the settlement of liabilities subject to compromise	$ —	$ 6,443	$ 12
Accrual for allowed claims	—	(1,002)	(879)
Write off of unamortized debt premiums (discounts) on Predecessor debt	—	—	518
Write off of unamortized debt issuance costs on Predecessor debt	—	—	(61)
Gain on fresh start adjustments	—	201	—
Gain from release of commitment liabilities	—	55	—
Debt and equity financing fees	—	—	(145)
Loss on divested assets	—	—	(128)
Professional service provider fees and other	—	(60)	(113)
Success fees for professional service providers	—	(38)	—
Surrender of other receivable	—	(18)	—
FLLO alternative transaction fee	—	(12)	—
Total reorganization items, net	$ —	$ 5,569	$ (796)

In the 2021 and 2020 Predecessor Periods, we recorded a net gain of $5.569 billion and a net loss of $796 million, respectively, in reorganization items, net, related to the Chapter 11 Cases. See Note 2 and Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a discussion of the Chapter 11 Cases and for discussion of adoption of fresh start accounting.

Income Tax Expense (Benefit). We recorded an income tax benefit of $49 million in the 2021 Successor Period. In the 2021 and 2020 Predecessor Periods, we recorded an income tax benefit of $57 million and $19 million, respectively. The income tax benefit recorded in the 2021 Successor Period is related to a $49 million partial release of the valuation allowance maintained against our net deferred tax asset position. The partial release was a consequence of recording a net deferred tax liability of $49 million resulting from the business combination accounting for Vine. The $57 million income tax benefit for the 2021 Predecessor Period consists of the removal of the income tax effects in other comprehensive income related to hedging settlements due to the fair value adjustments made upon emergence from bankruptcy. The income tax benefit for the 2020 Predecessor Period consists of a reversal of the income tax expense recorded in 2019 of $10 million relating to Texas no longer being in a net deferred tax asset position for the period ended December 31, 2019. Texas reverted back to being in a net deferred tax asset position which was offset by a valuation allowance for the period ended December 31, 2020, which resulted in the reversal. The $19 million also includes a current state income tax benefit of $6 million and a $3 million benefit for amounts which were previously sequestered or anticipated to be sequestered by the Internal Revenue Service (IRS) against certain refunds of alternative minimum tax (AMT) credits. The IRS announced on January 16, 2020, that refunds of AMT credits should not have been subject to sequestration. All previously sequestered funds have been received. See Note 11 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a discussion of income tax expense (benefit).

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions that involve a significant level of estimation uncertainty and have or are reasonably likely to have a material impact on our financial condition or results of operations are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Reorganization and Fresh Start Accounting. Effective June 28, 2020, as a result of the filing of the Chapter 11 Cases we began accounting and reporting according to FASB ASC Topic 852 – Reorganizations ("ASC 852"), which specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements include distinguishing and presenting transactions associated with the reorganization and implementation of the plan of reorganization separately from activities related to ongoing operations of the business. Additionally, upon emergence from the Chapter 11 Cases, ASC 852 required us to allocate our reorganization value to our individual assets based on their estimated fair values, resulting in a new entity for financial reporting purposes. After the Effective Date, the accounting and reporting requirements of ASC 852 are no longer applicable and have no impact on the Successor periods.

Oil and Natural Gas Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas or NGL prices could result in actual results differing significantly from our estimates. See *Supplemental Disclosures About Oil, Natural Gas, and NGL Producing Activities* included in Item 8 of Part II of this report for further information.

Accounting for Business Combinations. We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 – Business Combinations, and involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based on the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess, if any, of the consideration given to acquire an entity over the net amounts assigned to its assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity is recognized immediately to earnings as a gain from bargain purchase.

The Company's principal assets are its oil and natural gas properties, which are accounted for under the successful efforts accounting method. The Company determines the fair value of acquired oil and natural gas properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area are prepared using the estimated future revenues and operating costs for all proved developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area. The Company utilizes NYMEX strip pricing, adjusted for differentials, to value the reserves. The NYMEX strip pricing inputs used are classified as Level 1 fair value assumptions and all other inputs are classified as Level 3 fair value assumptions. The discount rates utilized are derived using a weighted average cost of capital computation, which includes an estimated cost of debt and equity for market participants with similar geographies and asset development type by operating area.

Impairments. Long-lived assets used in operations, including proved oil and gas properties, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value by discounting using a weighted average cost of capital. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach. Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include our estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves and other relevant data. Additionally, we utilize NYMEX strip pricing, adjusted for differentials, to value the reserves.

Income Taxes. Income taxes are accounted for using the asset and liability method as required by GAAP. Deferred tax assets and liabilities arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets for tax attributes such as NOL carryforwards and disallowed business interest carryforwards are also recognized. Deferred tax assets represent potential future tax benefits, and are reduced by a valuation allowance if it is more likely than not that such benefits will not be realized.

In assessing the need for a valuation allowance or adjustments to existing valuation allowances, we consider the weight of all available evidence, both positive and negative, concerning the realization of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- reversal of existing deferred tax liabilities against deferred tax assets and whether the carryforward period is so brief that it would limit realization of the tax benefit;
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- our earnings history exclusive of any loss that creates a future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Our judgement regarding the realizability of deferred tax assets is thus significantly informed by our assessment of forecasted financial information.

In interim quarters our tax provision is based upon an estimated annual effective tax rate, which is determined through the usage of full year estimates. Thus, our quarterly income tax expense or benefit can fluctuate throughout the year as a result of changing financial forecasts.

We also routinely assess potential uncertain tax positions and, if required, establish accruals for such positions. Accounting guidance for recognizing and measuring uncertain tax positions requires that a more likely than not threshold condition be met on a tax position, based solely on its technical merits of being sustained, before any benefit of the uncertain tax position can be recognized in the financial statements. If it is more likely than not a tax position will be sustained, we measure and recognize the position following a cumulative probability estimate.

Contingencies. We are subject to various legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, we accrue losses when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Our in-house legal personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of our liability for these contingencies.

We make judgments and estimates when we establish liabilities for litigation and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to us. The extent of information available varies based on the status of the litigation and our evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change our estimate of litigation-related liabilities, including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, we evaluate the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to our risk of loss arising from adverse changes in oil, natural gas, and NGL prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Price Risk

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL, which have historically been volatile. To mitigate a portion of our exposure to adverse price changes, we enter into various derivative instruments. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

We determine the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements that require counterparties to post collateral if their obligations to us are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of the fair value measurements associated with our derivatives.

For the combined 2021 Successor and Predecessor Periods, oil, natural gas, and NGL revenues, excluding any effect of our derivative instruments, were $1.735 billion, $2.818 billion, and $246 million, respectively. Based on production, oil, natural gas, and NGL revenue for the combined 2021 Successor and Predecessor Periods would have increased or decreased by approximately $173 million, $282 million, and $25 million, respectively, for each 10% increase or decrease in prices. As of December 31, 2021, the fair values of our oil and natural gas derivatives were net liabilities of $358 million and net liabilities of $785 million, respectively. A 10% increase in forward oil prices would decrease the valuation of oil derivatives by $95 million while a 10% decrease would increase the valuation by $95 million. A 10% increase in forward natural gas prices would decrease the valuation of natural gas derivatives by approximately $270 million while a 10% decrease would increase the valuation by $269 million. This fair value change assumes volatility based on prevailing market parameters at December 31, 2021. See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further information on our open derivative positions.

Interest Rate Risk

Our exposure to interest rate changes relates primarily to borrowings under our Exit Credit Facility for the 2021 Successor Period and pre-petition revolving credit facility and DIP Facility for the 2021, 2020 and 2019 Predecessor Periods. Interest is payable on borrowings under the Exit Credit Facility, pre-petition revolving credit facility and DIP Credit Facility based on a floating rate. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information. As of December 31, 2021, we had no outstanding borrowings under our Exit Credit Facility - Tranche A Loans, and $221 million under our Exit Credit Facility - Tranche B Loans. A 1.0% increase in interest rates based on the variable borrowings as of December 31, 2021 would result in an increase in our interest expense of approximately $2 million per year. Changes in interest rates do affect the fair value of our fixed-rate debt.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

Supplementary Information:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Chesapeake Energy Corporation and its subsidiaries (Successor) (the “Company”) as of December 31, 2021, and the related consolidated statements of operations, of comprehensive income (loss), of stockholders’ equity and of cash flows for the period from February 10, 2021 through December 31, 2021, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021, and the results of its operations and its cash flows for the period from February 10, 2021 through December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis of Accounting

As discussed in Note 2 to the consolidated financial statements, Chesapeake Energy Corporation and certain of its subsidiaries (collectively the “Debtors”) filed voluntary petitions on June 28, 2020 with the United States Bankruptcy Court for the Southern District of Texas for relief under the provisions of Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Debtors’ joint plan of reorganization on January 16, 2021 and the Debtors emerged from bankruptcy on February 9, 2021. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting as of February 9, 2021.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audit 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 consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audit of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Vine Energy Inc. from its assessment of internal control over financial reporting as of December 31, 2021, because it was acquired by the Company in a purchase business combination during 2021. We have also excluded Vine Energy Inc. from our audit of internal control over financial reporting. Vine Energy Inc. is a wholly-owned subsidiary whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting represent 20% and 7%, respectively, of the related consolidated financial statement amounts as of December 31, 2021 and for the period from February 10, 2021 through December 31, 2021.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the 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.

Critical Audit Matters

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

The Impact of Proved Oil and Natural Gas Reserves on Proved Oil and Natural Gas Properties, Net

As described in Note 1 to the consolidated financial statements, the Company's property and equipment, net balance was approximately $8.8 billion as of December 31, 2021, and depreciation, depletion, and amortization (DD&A) expense for the period from February 10, 2021 through December 31, 2021 was approximately $919 million, both of which substantially related to proved oil and natural gas properties. The Company follows the successful efforts method of accounting for its oil and natural gas properties. Under this method, all capitalized well costs and leasehold costs of proved oil and natural gas properties are depreciated by the units-of-production (UOP) method based on total estimated proved developed reserves and proved reserves, respectively. As disclosed by management, estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of management's estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves volumes may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. The estimates of proved oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on proved oil and natural gas properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserves volumes and the assumptions applied to the data related to the commodity pricing differentials and future development costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserves volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. These procedures also included, among others, testing the completeness and accuracy of the data related to commodity pricing differentials and future development costs. Additionally, these procedures included evaluating whether the assumptions applied to the aforementioned data were reasonable considering the past performance of the Company.

Acquisition of Vine Energy, Inc. - Valuation of Proved and Unproved Oil and Natural Gas Properties

As described in Note 4 to the consolidated financial statements, on November 1, 2021, the Company acquired Vine Energy, Inc. (Vine), an energy company focused on the development of natural gas properties in the over-pressured stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana. Accordingly, the Company recorded the estimated fair values of the acquired proved and unproved oil and natural gas properties of approximately $2.2 billion and approximately $1.1 billion for proved oil and gas properties and unproved properties, respectively. As disclosed by management, management determines the fair value of acquired oil and natural gas properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area are prepared using the estimated future revenues and operating costs for all proved developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area. The estimates of proved oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the valuation of the acquired Vine proved and unproved oil and natural gas properties is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fair value of proved and unproved oil and natural gas properties; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists related to recoverable reserves; production rates; future operating and development costs; future commodity prices escalated by an inflationary rate after five years, adjusted for differentials; and a market-based weighted average cost of capital by operating area; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included, among others, testing the effectiveness of controls relating to management's estimates of the fair value of proved and unproved oil and natural gas properties. These procedures also included, among others, (i) testing management's process for developing the fair value of proved and unproved oil and natural gas properties; (ii) evaluating the appropriateness of the discounted cash flow models; (iii) testing the completeness and accuracy of underlying data used in the models; and (iv) evaluating the data, methods, and significant assumptions used by management related to recoverable reserves, production rates, future operating and development costs, future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and a market-based weighted average cost of capital by operating area. Evaluating the reasonableness of management's assumptions related to future commodity prices adjusted for differentials involved comparing the prices against observable market data and evaluating differentials through inspection of the underlying contracts. Evaluating future operating and development costs involved evaluating the reasonableness of the costs as compared to the past performance of the acquired business, comparing to the current performance of the Company, consistency with external market and industry data, and whether the assumptions were consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the recoverable reserves and production rates. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the data, methods, and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. Professionals with specialized skill and knowledge were used to assist in the evaluation of the Company's discounted cash flow models and market-based weighted average cost of capital by operating area.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 24, 2022

We have served as the Company's auditor since 1992.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Chesapeake Energy Corporation and its subsidiaries (Predecessor) (the "Company") as of December 31, 2020, and the related consolidated statements of operations, of comprehensive income (loss), of stockholders' equity and of cash flows for the period from January 1, 2021 through February 9, 2021 and for the years ended December 31, 2020 and 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020, and the results of its operations and its cash flows for the period from January 1, 2021 through February 9, 2021 and for the years ended December 31, 2020 and 2019 in conformity with accounting principles generally accepted in the United States of America.

Basis of Accounting

As discussed in Note 2 to the consolidated financial statements, Chesapeake Energy Corporation and certain of its subsidiaries (collectively the "Debtors") filed voluntary petitions on June 28, 2020 with the United States Bankruptcy Court for the Southern District of Texas for relief under the provisions of Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Debtors' joint plan of reorganization on January 16, 2021 and the Debtors emerged from bankruptcy on February 9, 2021. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting. This matter is also described in the "Critical Audit Matters" section of our report.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated 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 it relates.

Valuation of Proved and Unproved Oil and Natural Gas Properties in Connection with the Application of Fresh Start Accounting

As described in Note 3 to the consolidated financial statements, in connection with the Company's emergence from bankruptcy, management applied fresh start accounting on February 9, 2021 and recorded the estimated fair values of its proved and unproved oil and natural gas properties of approximately $4.7 billion and approximately $483 million, respectively. Management determined the fair value of its oil and natural gas properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area were prepared using the estimated future revenues and operating costs for all developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area.

The principal considerations for our determination that performing procedures relating to the valuation of proved and unproved oil and natural gas properties in connection with the application of fresh start accounting is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fair value of proved and unproved oil and natural gas properties; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists related to recoverable reserves, production rates, future operating and development costs, future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and a market-based weighted average cost of capital by operating area; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included, among others, (i) testing management's process for developing the fair value of proved and unproved oil and natural gas properties; (ii) evaluating the appropriateness of the discounted cash flow models; (iii) testing the completeness and accuracy of underlying data used in the models; and (iv) evaluating the data, methods, and significant assumptions used by management related to recoverable reserves, production rates, future operating and development costs, future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and a market-based weighted average cost of capital by operating area. Evaluating the reasonableness of management's assumptions related to future commodity prices adjusted for differentials involved comparing the prices against observable market data and evaluating differentials through inspection of the underlying contracts. Evaluating future operating costs involved evaluating the reasonableness of the costs as compared to the past performance of the Company. Evaluating future development costs involved evaluating whether the costs were reasonable considering the current performance of the Company, the consistency with external market and industry data, and whether the assumption was consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the recoverable reserves and production rates. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the data, methods, and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. Professionals with specialized skill and knowledge were used to assist in the evaluation of the Company's discounted cash flow models and market-based weighted average cost of capital by operating area.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 24, 2022

We have served as the Company's auditor since 1992.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 905	$ 279
Restricted cash	9	—
Accounts receivable, net	1,115	746
Short-term derivative assets	5	19
Other current assets	69	64
Total current assets	2,103	1,108
Property and equipment:		
Oil and natural gas properties, successful efforts method		
Proved oil and natural gas properties	7,682	25,734
Unproved properties	1,530	1,550
Other property and equipment	495	1,754
Total property and equipment	9,707	29,038
Less: accumulated depreciation, depletion and amortization	(908)	(23,806)
Property and equipment held for sale, net	3	10
Total property and equipment, net	8,802	5,242
Other long-term assets	104	234
Total assets	$ 11,009	$ 6,584

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS – (Continued)

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Liabilities and stockholders' equity (deficit)		
Current liabilities:		
Accounts payable	$ 308	$ 346
Current maturities of long-term debt, net	—	1,929
Accrued interest	38	3
Short-term derivative liabilities	899	93
Other current liabilities	1,202	723
Total current liabilities	2,447	3,094
Long-term debt, net	2,278	—
Long-term derivative liabilities	249	44
Asset retirement obligations, net of current portion	349	139
Other long-term liabilities	15	5
Liabilities subject to compromise	—	8,643
Total liabilities	5,338	11,925
Contingencies and commitments (Note 7)		
Stockholders' equity (deficit):		
Predecessor preferred stock, $0.01 par value, 20,000,000 shares authorized: 0 and 5,563,458 shares outstanding	—	1,631
Predecessor common stock, $0.01 par value, 22,500,000 shares authorized: 0 and 9,780,547 shares issued	—	—
Predecessor additional paid-in capital	—	16,937
Predecessor accumulated other comprehensive income	—	45
Successor common stock, $0.01 par value, 450,000,000 shares authorized: 117,917,349 and 0 shares issued	1	—
Successor additional paid-in capital	4,845	—
Retained earnings (accumulated deficit)	825	(23,954)
Total stockholders' equity (deficit)	5,671	(5,341)
Total liabilities and stockholders' equity (deficit)	$ 11,009	$ 6,584

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Revenues and other:				
Oil, natural gas and NGL	$ 4,401	$ 398	$ 2,745	$ 4,517
Marketing	2,263	239	1,869	3,967
Oil and natural gas derivatives	(1,127)	(382)	596	5
Gains on sales of assets	12	5	30	43
Total revenues and other	5,549	260	5,240	8,532
Operating expenses:				
Production	297	32	373	520
Gathering, processing and transportation	780	102	1,082	1,082
Severance and ad valorem taxes	158	18	149	224
Exploration	7	2	427	84
Marketing	2,257	237	1,889	4,003
General and administrative	97	21	267	315
Separation and other termination costs	11	22	44	12
Depreciation, depletion and amortization	919	72	1,097	2,264
Impairments	1	—	8,535	11
Other operating expense (income), net	84	(12)	80	48
Total operating expenses	4,611	494	13,943	8,563
Income (loss) from operations	938	(234)	(8,703)	(31)
Other income (expense):				
Interest expense	(73)	(11)	(331)	(651)
Gains on purchases or exchanges of debt	—	—	65	75
Other income (expense)	31	2	(4)	(32)
Reorganization items, net	—	5,569	(796)	—
Total other income (expense)	(42)	5,560	(1,066)	(608)
Income (loss) before income taxes	896	5,326	(9,769)	(639)
Income tax benefit	(49)	(57)	(19)	(331)
Net income (loss)	945	5,383	(9,750)	(308)
Net loss attributable to noncontrolling interests	—	—	16	—
Net income (loss) attributable to Chesapeake	945	5,383	(9,734)	(308)
Preferred stock dividends	—	—	(22)	(91)
Loss on exchange of preferred stock	—	—	—	(17)
Net income (loss) available to common stockholders	$ 945	$ 5,383	$ (9,756)	$ (416)
Earnings (loss) per common share:				
Basic	$ 9.29	$ 550.35	$ (998.26)	$ (49.97)
Diluted	$ 8.12	$ 534.51	$ (998.26)	$ (49.97)
Weighted average common shares outstanding (in thousands):				
Basic	101,754	9,781	9,773	8,325
Diluted	116,341	10,071	9,773	8,325

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Net income (loss)	$ 945	$ 5,383	$ (9,750)	$ (308)
Other comprehensive income, net of income tax:				
Reclassification of losses on settled derivative instruments[(a)]	—	3	33	35
Other comprehensive income	—	3	33	35
Comprehensive income (loss)	945	5,386	(9,717)	(273)
Comprehensive loss attributable to noncontrolling interests	—	—	16	—
Comprehensive income (loss) attributable to Chesapeake	$ 945	$ 5,386	$ (9,701)	$ (273)

(a) Deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash flows from operating activities:				
Net income (loss)	$ 945	$ 5,383	$ (9,750)	$ (308)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	919	72	1,097	2,264
Deferred income tax benefit	(49)	(57)	(10)	(305)
Derivative (gains) losses, net	1,127	382	(596)	(3)
Cash receipts (payments) on derivative settlements, net	(1,142)	(17)	884	202
Share-based compensation	9	3	21	30
Gains on sales of assets	(12)	(5)	(30)	(43)
Impairments	1	—	8,535	11
Non-cash reorganization items, net	—	(6,680)	(213)	—
Exploration	2	2	417	49
Gains on purchases or exchanges of debt	—	—	(65)	(79)
Other	46	45	(41)	59
Changes in assets and liabilities	(37)	851	915	(254)
Net cash provided by (used in) operating activities	1,809	(21)	1,164	1,623
Cash flows from investing activities:				
Capital expenditures	(669)	(66)	(1,142)	(2,263)
Business combination, net	(194)	—	—	(353)
Proceeds from divestitures of property and equipment	13	—	150	136
Net cash used in investing activities	(850)	(66)	(992)	(2,480)
Cash flows from financing activities:				
Proceeds from Exit Credit Facility - Tranche A Loans	30	—	—	—
Payments on Exit Credit Facility - Tranche A Loans	(80)	(479)	—	—
Proceeds from pre-petition revolving credit facility borrowings	—	—	3,656	10,676
Payments on pre-petition revolving credit facility borrowings	—	—	(3,317)	(10,180)
Proceeds from DIP Facility borrowings	—	—	60	—
Payments on DIP Facility borrowings	—	(1,179)	(60)	—
Proceeds from issuance of senior notes, net	—	1,000	—	108
Proceeds from issuance of term loan, net	—	—	—	1,455
Proceeds from issuance of common stock	—	600	—	—
Proceeds from warrant exercise	2	—	—	—
Debt issuance and other financing costs	(3)	(8)	(109)	—
Cash paid to purchase debt	—	—	(94)	(1,073)
Cash paid for common stock dividends	(119)	—	—	—
Cash paid for preferred stock dividends	—	—	(22)	(91)
Other	(1)	—	(13)	(36)
Net cash provided by (used in) financing activities	(171)	(66)	101	859
Net increase (decrease) in cash, cash equivalents and restricted cash	788	(153)	273	2
Cash, cash equivalents and restricted cash, beginning of period	126	279	6	4
Cash, cash equivalents and restricted cash, end of period	$ 914	$ 126	$ 279	$ 6

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash and cash equivalents	$ 905	$ 40	$ 279	$ 6
Restricted cash	9	86	—	—
Total cash, cash equivalents and restricted cash	$ 914	$ 126	$ 279	$ 6

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Supplemental cash flow information:				
Cash paid for reorganization items, net	$ 65	$ 66	$ 140	$ —
Interest paid, net of capitalized interest	$ 34	$ 13	$ 224	$ 691
Income taxes paid, net of refunds received	$ (9)	$ —	$ —	$ (6)
Supplemental disclosure of significant non-cash investing and financing activities:				
Change in accrued drilling and completion costs	$ 30	$ (5)	$ (216)	$ (19)
Put option premium on equity backstop agreement	$ —	$ 60	$ 60	$ —
Operating lease obligations recognized	$ —	$ —	$ 32	$ —
Common stock issued for business combination	$ 1,232	$ —	$ —	$ 2,037
Debt exchanged for common stock	$ —	$ —	$ —	$ 693
Preferred stock exchanged for common stock	$ —	$ —	$ —	$ 40
Change in senior notes exchanged	$ —	$ —	$ —	$ 971

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Attributable to Chesapeake									
	Preferred Stock		Common Stock							
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Treasury Stock	Non-controlling Interest	Total Stockholders' Equity (Deficit)
Balance as of December 31, 2020 (Predecessor)	5,563,358	$ 1,631	9,780,547	$ —	$ 16,937	$ (23,954)	$ 45	$ —	$ —	$ (5,341)
Share-based compensation	—	—	67	—	3	—	—	—	—	3
Hedging activity	—	—	—	—	—	—	3	—	—	3
Net income	—	—	—	—	—	5,383	—	—	—	5,383
Cancellation of Predecessor equity	(5,563,358)	(1,631)	(9,780,614)	—	(16,940)	18,571	(48)	—	—	(48)
Issuance of Successor common stock	—	—	97,907,081	1	3,330	—	—	—	—	3,331
Issuance of Successor Class A warrants	—	—	—	—	93	—	—	—	—	93
Issuance of Successor Class B warrants	—	—	—	—	94	—	—	—	—	94
Issuance of Successor Class C warrants	—	—	—	—	68	—	—	—	—	68
Balance as of February 9, 2021 (Predecessor)	—	$ —	97,907,081	$ 1	$ 3,585	$ —	$ —	$ —	$ —	$ 3,586
Balance as of February 10, 2021 (Successor)	—	$ —	97,907,081	$ 1	$ 3,585	$ —	$ —	$ —	$ —	$ 3,586
Share-based compensation	—	—	248,487	—	21	—	—	—	—	21
Issuance of common stock for Vine acquisition	—	—	18,709,399	—	1,237	—	—	—	—	1,237
Issuance of common stock for warrant exercise	—	—	188,292	—	2	—	—	—	—	2
Issuance of reserved common stock and warrants	—	—	864,090	—	—	—	—	—	—	—
Net income	—	—	—	—	—	945	—	—	—	945
Dividends on common stock	—	—	—	—	—	(120)	—	—	—	(120)
Balance as of December 31, 2021 (Successor)	—	$ —	117,917,349	$ 1	$ 4,845	$ 825	$ —	$ —	$ —	$ 5,671

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY - (Continued)

	Attributable to Chesapeake									
	Preferred Stock		Common Stock		Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Treasury Stock	Non-controlling Interest	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount						
Balance as of December 31, 2019 (Predecessor)	5,563,458	$ 1,631	9,772,793	$ —	$ 16,973	$ (14,220)	$ 12	$ (32)	$ 37	$ 4,401
Share-based compensation	—	—	7,753	—	(14)	—	—	—	—	(14)
Dividends on preferred stock	—	—	—	—	(22)	—	—	—	—	(22)
Hedging activity	—	—	—	—	—	—	33	—	—	33
Net loss attributable to Chesapeake	—	—	—	—	—	(9,734)	—	—	—	(9,734)
Exchange of preferred stock into common stock	(100)	—	1	—	—	—	—	—	—	—
Purchase of shares for company benefit plans	—	—	—	—	—	—	—	(2)	—	(2)
Release of shares for company benefit plans	—	—	—	—	—	—	—	34	—	34
Net loss attributable to noncontrolling interests	—	—	—	—	—	—	—	—	(16)	(16)
Divestiture of underlying assets	—	—	—	—	—	—	—	—	(21)	(21)
Balance as of December 31, 2020 (Predecessor)	5,563,358	$ 1,631	9,780,547	$ —	$ 16,937	$ (23,954)	$ 45	$ —	$ —	$ (5,341)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY - (Continued)

	Attributable to Chesapeake									
	Preferred Stock		Common Stock							
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Treasury Stock	Non-controlling Interest	Total Stockholders' Equity
Balance as of December 31, 2018 (Predecessor)	5,603,458	$ 1,671	4,568,581	$ —	$ 14,387	$ (13,912)	$ (23)	$ (31)	$ 41	$ 2,133
Common shares issued for WildHorse Merger	—	—	3,586,880	—	2,037	—	—	—	—	2,037
Share-based compensation	—	—	20,731	—	27	—	—	—	—	27
Dividends on preferred stock	—	—	—	—	(91)	—	—	—	—	(91)
Hedging activity	—	—	—	—	—	—	35	—	—	35
Net loss attributable to Chesapeake	—	—	—	—	—	(308)	—	—	—	(308)
Exchange of contingent convertible notes into common stock	—	—	366,945	—	135	—	—	—	—	135
Exchange of senior notes into common stock	—	—	1,177,817	—	440	—	—	—	—	440
Exchange of preferred stock into common stock	(40,000)	(40)	51,839	—	40	—	—	—	—	—
Equity component of contingent convertible notes repurchased	—	—	—	—	(2)	—	—	—	—	(2)
Purchase of shares for company benefit plans	—	—	—	—	—	—	—	(7)	—	(7)
Release of shares for company benefit plans	—	—	—	—	—	—	—	6	—	6
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	—	(4)	(4)
Balance as of December 31, 2019 (Predecessor)	5,563,458	$ 1,631	9,772,793	$ —	$ 16,973	$ (14,220)	$ 12	$ (32)	$ 37	$ 4,401

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake," “we,” “our,” “us” or the "Company") is an oil and natural gas exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and NGL from underground reservoirs. Our operations are located onshore in the United States. As discussed in Note 2 below, we filed the Chapter 11 Cases on the Petition Date and subsequently operated as a debtor-in-possession, in accordance with applicable provisions of the Bankruptcy Code, until emergence on February 9, 2021. To facilitate our financial statement presentations, we refer to the post-emergence reorganized Company in these consolidated financial statements and footnotes as the “Successor” for periods subsequent to February 9, 2021, and to the pre-emergence Company as “Predecessor” for periods on or prior to February 9, 2021.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake were prepared in accordance with GAAP and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated. The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern.

This Annual Report on Form 10-K (this “Form 10-K”) relates to the financial position of the Successor as of December 31, 2021 and Predecessor as of December 31, 2020, and the periods of February 10, 2021 through December 31, 2021 (“2021 Successor Period”), January 1, 2021 through February 9, 2021 (“2021 Predecessor Period”), and the years ended December 31, 2020 (“2020 Predecessor Period”) and December 31, 2019 (“2019 Predecessor Period”).

Accounting During Bankruptcy

We have applied Accounting Standards Codification (ASC) 852, *Reorganizations,* in preparing the consolidated financial statements. ASC 852 requires that the financial statements, for periods subsequent to the filing of a petition of Chapter 11 Cases, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that were realized or incurred during the bankruptcy proceedings, including losses related to executory contracts that were approved for rejection by the Bankruptcy Court, and unamortized debt issuance costs, premiums and discounts associated with debt classified as liabilities subject to compromise, are recorded as reorganization items, net on our accompanying consolidated statements of operations. In addition, pre-petition obligations that could have been impacted by the Chapter 11 process have been classified on the consolidated balance sheet as of December 31, 2020, as liabilities subject to compromise. See Note 2 for more information regarding reorganization items.

Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the related disclosures in the financial statements. Management evaluates its estimates and related assumptions regularly, including those related to the impairment of oil and natural gas properties, oil and natural gas reserves, derivatives, income taxes, unevaluated properties not subject to evaluation, impairment of other property and equipment, environmental remediation costs, asset retirement obligations, litigation and regulatory proceedings and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ significantly from these estimates.

Consolidation

We consolidate entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights and variable interest entities ("VIEs") in which we are the primary beneficiary. We consolidate a VIE when we are the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE's economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform a qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements. See Note 12 for further discussion of our previous VIE. We use the equity method of accounting to record our net interests where we have the ability to exercise significant influence through our investment but lack a controlling financial interest. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. Undivided interests in oil and natural gas properties are consolidated on a proportionate basis.

Segments

Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating an enterprise's resources and assessing its operating performance. We have concluded that we have only one reportable operating segment, due to the similar nature of the exploration and production business across Chesapeake and its consolidated subsidiaries and the fact that our marketing activities are ancillary to our operations.

Noncontrolling Interests

Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries and are presented as a component of equity. See Note 12 for further discussion of noncontrolling interests.

Cash and Cash Equivalents

For purposes of the consolidated financial statements, we consider investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents.

Restricted Cash

As of December 31, 2021, we had restricted cash of $9 million. The restricted funds are maintained primarily to pay certain convenience class unsecured claims following our emergence from bankruptcy.

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. See Note 10 for further discussion of our accounts receivable.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, exploration costs such as exploratory geological and geophysical costs, expiration of unproved leasehold, delay rentals and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead and similar activities are also expensed as incurred. All property acquisition costs and development costs are capitalized when incurred.

Exploratory drilling costs are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If we determine that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. We review the status of all suspended exploratory drilling costs quarterly. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of oil and natural gas are capitalized.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production ("UOP") method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves.

Proceeds from the sales of individual oil and natural gas properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depreciation, depletion and amortization, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recognized until an entire amortization base is sold. However, a gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

When circumstances indicate that the carrying value of proved oil and natural gas properties may not be recoverable, we compare unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on our estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820, *Fair Value Measurements*. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of commodity prices, pricing adjustments for differentials, operating costs, capital investment plans, future production volumes, and estimated proved reserves, considering all available information at the date of review. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted average cost of capital. We have classified these fair value measurements as Level 3 in the fair value hierarchy.

Other Property and Equipment

Other property and equipment consists primarily of buildings and improvements, land, vehicles, computers and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. Other property and equipment costs, excluding land, are depreciated on a straight-line basis and recorded within depreciation, depletion and amortization in the consolidated statement of operations.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including any disposal value, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets and discounted cash flow. See Note 17 for further discussion of other property and equipment.

Capitalized Interest

Interest from external borrowings is capitalized on significant investments in major development projects until the asset is ready for service using the weighted average borrowing rate of outstanding borrowings. Capitalized interest is determined by multiplying our weighted average borrowing cost on debt by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

Accounts Payable

Included in accounts payable as of December 31, 2021 are liabilities of approximately $23 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. There were no corresponding liabilities as of December 31, 2020.

Debt Issuance Costs

Costs associated with the arrangement of our Exit Credit Facility are included in other long-term assets and are amortized over the life of the facility using the straight-line method. The Exit Credit Facility unamortized issuance costs as of December 31, 2021 were $23 million. Costs associated with the issuance of the Successor senior notes are included in long-term debt and the remaining unamortized issuance costs are amortized over the life of the senior notes using the effective interest method. Unamortized issuance costs associated with the Successor senior notes as of December 31, 2021 totaled $9 million.

Costs associated with the issuance and amendments of our pre-petition revolving credit facility were included in other long-term assets and the remaining unamortized issuance costs were being amortized over the life of the facility using the straight-line method. Costs associated with the issuance of our Predecessor senior notes were included in long-term debt and the remaining unamortized issuance costs were being amortized over the life of the Predecessor senior notes using the effective interest method. In 2020, our Chapter 11 Cases constituted an event of default under our pre-petition revolving credit facility and our senior notes, and non-cash adjustments were made to write off all related unamortized debt issuance costs which are included in reorganization items, net in the accompanying consolidated statements of operations for the year ended December 31, 2020. See Note 2 and Note 6 herein for further discussion of our Chapter 11 Cases and debt issuance costs, respectively.

Litigation Contingencies

We are subject to litigation and regulatory proceedings, claims and liabilities that arise in the ordinary course of business. We accrue losses associated with litigation and regulatory claims when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, our best estimate within the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or third-party recoveries. Legal defense costs associated with loss contingencies are expensed in the period incurred. See Note 7 for further discussion of litigation contingencies.

Environmental Remediation Costs

We record environmental reserves for estimated remediation costs related to existing conditions from past operations when the responsibility to remediate is probable and the costs can be reasonably estimated. Expenditures that create future benefits or contribute to future revenue generation are capitalized. See Note 7 for discussion of environmental contingencies.

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. See Note 23 for further discussion of asset retirement obligations.

Revenue Recognition

Revenue from the sale of oil, natural gas and NGL is recognized upon the transfer of control of the products, which is typically when the products are delivered to customers. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration we expect to receive in exchange for those products.

Revenue from contracts with customers includes the sale of our oil, natural gas and NGL production (recorded as oil, natural gas and NGL revenues in the consolidated statements of operations) as well as the sale of certain of our joint interest holders' production which we purchase under joint operating arrangements (recorded in marketing revenues in the consolidated statements of operations). In connection with the marketing of these products, we obtain control of the oil, natural gas and NGL we purchase from other interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded.

Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 days. There are no significant judgments that significantly affect the amount or timing of revenue from contracts with customers.

We also generate revenue from other sources, including from a variety of derivative and hedging activities to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility, as well as a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and satisfaction of our pipeline delivery commitments (recorded within marketing revenues in the consolidated statements of operations).

In circumstances where we act as an agent rather than a principal, our results of operations related to oil, natural gas and NGL marketing activities are presented on a net basis. See Note 10 for further discussion of revenue recognition.

Fair Value Measurements

Certain financial instruments are reported on a recurring basis at fair value on our consolidated balance sheets. We also use fair value measurements on a nonrecurring basis when a qualitative assessment of our assets indicates a potential impairment. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments. See Notes 6 and 15 for further discussion of fair value measurements.

Derivatives

Derivative instruments are recorded at fair value, and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are followed. As of December 31, 2021, none of our open derivative instruments were designated as cash flow hedges.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows. All of our derivative instruments are subject to master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. See Note 15 for further discussion of our derivative instruments.

Share-Based Compensation

Our share-based compensation program consists of restricted stock, performance share units and cash restricted stock units granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. We recognize the cost of services received in exchange for restricted stock based on the fair value of the equity instruments as of the grant date. This value is amortized over the vesting period, which is generally three years from the grant date. Because performance share units are settled in shares, they are classified as equity and are measured at fair value as of the grant date.

To the extent compensation expense relates to employees directly involved in the acquisition of oil and natural gas leasehold and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expense, production expense, exploration expense, or marketing expense, based on the employees involved in those activities. See Note 13 for further discussion of share-based compensation.

Liability Management

Liability management expense includes third party legal and professional service fees incurred for our activities to restructure our debt and in preparation for our bankruptcy petition. As a result of our Chapter 11 Cases, such expenses, to the extent that they were incremental and directly related to our bankruptcy reorganization, are reflected in reorganization items, net in our consolidated statements of operations.

2. Chapter 11 Proceedings

On June 28, 2020 (the "Petition Date"), the Debtors filed voluntary petitions for relief under the Bankruptcy Code in the Bankruptcy Court. On June 29, 2020, the Bankruptcy Court entered an order authorizing the joint administration of the Chapter 11 Cases under the caption *In re Chesapeake Energy Corporation*, Case No. 20-33233. The Non-Filing Entities were not part of the Chapter 11 Cases. The Debtors and the Non-Filing Entities continued to operate in the ordinary course of business during the Chapter 11 Cases.

The Bankruptcy Court confirmed the Plan in a bench ruling on January 13, 2021 and entered the Confirmation Order on January 16, 2021. The Debtors emerged from bankruptcy on February 9, 2021 (the "Effective Date"). The Company's bankruptcy proceedings and related matters have been summarized below.

Debtor-In-Possession

During the pendency of the Chapter 11 Cases, we operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted the first day relief we requested that was designed primarily to mitigate the impact of the Chapter 11 Cases on our operations, vendors, suppliers, customers and employees. As a result, we were able to conduct normal business activities and pay all associated obligations for the period following the Petition Date and were also authorized to pay mineral interest owner royalties, employee wages and benefits, and certain vendors and suppliers in the ordinary course for goods and services provided prior to the Petition Date. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business required the prior approval of the Bankruptcy Court.

Automatic Stay

Subject to certain specific exceptions under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically stayed all judicial or administrative actions against us and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. Absent an order from the Bankruptcy Court, substantially all of the Debtors' pre-petition liabilities were subject to compromise and discharge under the Bankruptcy Code. The automatic stay was lifted on the Effective Date.

Plan of Reorganization

In accordance with the Plan confirmed by the Bankruptcy Court, the following significant transactions occurred upon the Company's emergence from bankruptcy on February 9, 2021:

- On the Effective Date, we issued 97,907,081 shares of the reorganized company ("New Common Stock"), reserved 2,092,918 shares of New Common Stock for future issuance to eligible holders of Allowed Unsecured Notes Claims and Allowed General Unsecured Claims and reserved 37,174,210 shares of New Common Stock for issuance upon exercise of the Warrants, which were the result of the transactions described below. We also entered into a registration rights agreement, a warrants agreement and amended our articles of incorporation and bylaws for the authorization of the New Common Stock and to provide registration rights thereunder, among other corporate governance actions. See Note 12 for further discussion of our post-emergence equity.

- Each holder of a Predecessor equity interest in Chesapeake, including our common and preferred stock, had such interest canceled, released, and extinguished without any distribution.

- Each holder of obligations under the pre-petition revolving credit facility received, at such holder's prior determined allocation, its pro rata share of either Tranche A Loans or Tranche B Loans, on a dollar for dollar basis.

- Each holder of obligations under the FLLO Term Loan Facility received its pro rata share of 23,022,420 shares of New Common Stock.

- Each holder of an Allowed Second Lien Notes Claim received its pro rata share of 3,635,118 shares of New Common Stock, 11,111,111 Class A Warrants to purchase 11,111,111 shares of New Common Stock, 12,345,679 Class B Warrants to purchase 12,345,679 shares of New Common Stock, and 6,858,710 Class C Warrants to purchase 6,858,710 shares of New Common Stock.

- Each holder of an Allowed Unsecured Notes Claim received its pro rata share of 1,311,089 shares of New Common Stock and 2,473,757 Class C Warrants to purchase 2,473,757 shares of New Common Stock.

- Each holder of an Allowed General Unsecured Claim received its pro rata share of 231,112 shares of New Common Stock and 436,060 Class C Warrants to purchase 436,060 shares of New Common Stock; provided that to the extent such Allowed General Unsecured Claim is a Convenience Claim, such holder instead received its pro rata share of $10 million, which pro rata share shall not exceed five percent of such Convenience Claim.

- Participants in the Rights Offering extending to the applicable classes under the Plan received 62,927,320 shares of New Common Stock.

- In connection with the rights offering described above, the Backstop Parties under the Backstop Commitment Agreement received 6,337,031 shares of New Common Stock in respect to the Put Option Premium, and 442,991 shares of New Common Stock were issued in connection with the backstop obligation thereunder to purchase unsubscribed shares of the New Common Stock.

- 2,092,918 shares of New Common Stock and 3,948,893 Class C Warrants were reserved for future issuance to eligible holders of Allowed Unsecured Notes Claims and Allowed General Unsecured Claims. The reserved New Common Stock and Class C Warrants will be issued on a pro rata basis upon the determination of the allowed portion of all disputed General Unsecured Claims and Unsecured Notes Claims.

- The 2021 Long Term Incentive Plan (the “LTIP”) was approved with a share reserve equal to 6,800,000 shares of New Common Stock.
- Each holder of an Allowed Other Secured Claim will receive, at the Company's option and in consultation with the Required Consenting Stakeholders (as defined in the Plan): (a) payment in full in cash; (b) the collateral securing its secured claim; (c) reinstatement of its secured claim; or (d) such other treatment that renders its secured claim unimpaired in accordance with Section 1124 of the Bankruptcy Code.
- Each holder of an Allowed Other Priority Claim (as defined in the Plan) will receive cash up to the allowed amount of its claim.

Additionally, pursuant to the Plan confirmed by the Bankruptcy Court, the Company’s post-emergence Board of Directors is comprised of seven directors, including the Company’s Chief Executive Officer, Domenic J. Dell’Osso Jr., the Company’s Executive Chairman, Michael Wichterich, and five non-employee directors, Timothy S. Duncan, Benjamin C. Duster, IV, Sarah Emerson, Matthew M. Gallagher and Brian Steck.

DIP and Exit Credit Facilities

On June 28, 2020, prior to the commencement of the Chapter 11 Cases, the Company entered into a commitment letter (the “Commitment Letter”) with certain of the lenders under the pre-petition revolving credit facility and/or their affiliates (collectively, the “Commitment Parties”), pursuant to which, and subject to the satisfaction of certain customary conditions, including the approval of the Bankruptcy Court, the Commitment Parties agreed to provide the Debtors with a post-petition senior secured super-priority debtor-in-possession revolving credit facility in an aggregate principal amount of up to approximately $2.104 billion (the “DIP Credit Facility”), consisting of a revolving loan facility of new money in an aggregate principal amount of up to $925 million, which includes a sub-facility of up to $200 million for the issuance of letters of credit, and an up to approximately $1.179 billion term loan that reflects the roll-up of a portion of outstanding borrowings under the pre-petition revolving credit facility. Pursuant to the Commitment Letter, the Commitment parties have also committed to provide, subject to certain conditions, an up to $2.5 billion exit credit facility, consisting of an up to $1.75 billion revolving credit facility (the “Exit Revolving Facility”) and an up to $750 million senior secured term loan facility (the “Exit Term Loan Facility” and, together with the Exit Revolving Facility, the “Exit Credit Facilities”). The terms and conditions of the DIP Credit Facility are set forth in the Senior Secured Super-Priority Debtor-in-Possession Credit Agreement (the “DIP Credit Agreement”) attached to the Commitment Letter. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases, payment of court approved adequate protection obligations, and other such purposes consistent with the DIP Credit Facility. On the Effective Date, the DIP Credit Facility was terminated and the holders of obligations under the DIP Credit Facility received payment in full in cash; provided that to the extent such lender under the DIP Credit Facility is also a lender under the Exit Revolver, such lender’s allowed DIP claims were first reduced dollar-for-dollar and satisfied by the amount of its Exit RBL Loans provided as of the Effective Date.

3. Fresh Start Accounting

Fresh Start Accounting

In connection with our emergence from bankruptcy and in accordance with ASC 852, we qualified for and applied fresh start accounting on the Effective Date. We were required to apply fresh start accounting because (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan of approximately $6.8 billion was less than the post-petition liabilities and allowed claims of $13.2 billion.

In accordance with ASC 852, with the application of fresh start accounting, the Company allocated its reorganization value to its individual assets based on their estimated fair value in conformity with FASB ASC Topic 820 - *Fair Value Measurements* and FASB ASC Topic 805 - *Business Combinations*. Accordingly, the consolidated financial statements after February 9, 2021 are not comparable with the consolidated financial statements as of or prior to that date. The Effective Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheet of the Predecessor.

Reorganization Value

Reorganization value is derived from an estimate of enterprise value, or fair value of the Company's interest-bearing debt and stockholders' equity. Under ASC 852, reorganization value generally approximates fair value of the entity before considering liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after the effects of a restructuring. As set forth in the disclosure statement, amended for updated pricing, and approved by the Bankruptcy Court, the enterprise value of the Successor was estimated to be between $3.5 billion and $4.9 billion. With the assistance of third-party valuation advisors, we determined the enterprise value and corresponding implied equity value of the Successor using various valuation approaches and methods, including: (i) income approach using a calculation of present value of future cash flows based on our financial projections, (ii) the market approach using selling prices of similar assets and (iii) the cost approach. For GAAP purposes, the Company valued the Successor's individual assets, liabilities and equity instruments and determined an estimate of the enterprise value within the estimated range. Management concluded that the best estimate of enterprise value was $4.85 billion. Specific valuation approaches and key assumptions used to arrive at reorganization value, and the value of discrete assets and liabilities resulting from the application of fresh start accounting, are described below in greater detail within the valuation process.

The enterprise value and corresponding implied equity value are dependent upon achieving the future financial results set forth in our valuation using an asset-based methodology of estimated proved reserves, undeveloped properties, and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the fresh start reporting date of February 9, 2021. All estimates, assumptions, valuations and financial projections, including the fair value adjustments, the financial projections, the enterprise value and equity value projections, are inherently subject to significant uncertainties and the resolution of contingencies beyond our control. Accordingly, there is no assurance that the estimates, assumptions, valuations or financial projections will be realized, and actual results could vary materially.

The following table reconciles the enterprise value to the implied fair value of the Successor's equity as of the Effective Date:

	February 9, 2021
Enterprise value	$ 4,851
Plus: Cash and cash equivalents[(a)]	48
Less: Fair value of debt	(1,313)
Successor equity value	$ 3,586

(a) Cash and cash equivalents includes $8 million that was initially classified as restricted cash as of the Effective Date but subsequently released from escrow and returned to the Successor. Restricted cash exclusive of the $8 million is not included in the table above.

The following table reconciles the enterprise value to the reorganization value as of the Effective Date:

	February 9, 2021
Enterprise value	$ 4,851
Plus: Cash and cash equivalents[a]	48
Plus: Current liabilities	1,582
Plus: Asset retirement obligations (non-current portion)	236
Plus: Other non-current liabilities	97
Reorganization value of Successor assets	$ 6,814

(a) Cash and cash equivalents includes $8 million that was initially classified as restricted cash as of the Effective Date but subsequently released from escrow and returned to the Successor. Restricted cash exclusive of the $8 million is not included in the table above.

Valuation Process

The fair values of our oil and natural gas properties, other property and equipment, other long-term assets, long-term debt, asset retirement obligations and warrants were estimated as of the Effective Date.

Oil and natural gas properties. The Company's principal assets are its oil and natural gas properties, which are accounted for under the successful efforts accounting method. The Company determined the fair value of its oil and natural gas properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area were prepared using the estimated future revenues and operating costs for all proved developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area. The Company utilized NYMEX strip pricing, adjusted for differentials, to value the reserves. The NYMEX strip pricing inputs used are classified as Level 1 fair value assumptions and all other inputs are classified as Level 3 fair value assumptions. The discount rates utilized were derived using a weighted average cost of capital computation, which included an estimated cost of debt and equity for market participants with similar geographies and asset development type by operating area.

Other property and equipment. The fair value of other property and equipment such as buildings, land, computer equipment, and other equipment was determined using replacement cost method under the cost approach which considers historical acquisition costs for the assets adjusted for inflation, as well as factors in any potential obsolescence based on the current condition of the assets and the ability of those assets to generate cash flow.

Long-term debt. A market approach, based upon quotes from major financial institutions, was used to measure the fair value of the $500 million aggregate principal amount of 5.50% Senior Notes due 2026 (the "2026 Notes") and $500 million aggregate principal amount of 5.875% Senior Notes due 2029 (the "2029 Notes" and, together with the 2026 Notes, the "Notes"). The carrying value of borrowings under our Exit Credit Facility approximated fair value as the terms and interest rates are based on prevailing market rates.

Asset retirement obligations. The fair value of the Company's asset retirement obligations was revalued based upon estimated current reclamation costs for our assets with reclamation obligations, an appropriate long-term inflation adjustment, and our revised credit adjusted risk-free rate. The credit adjusted risk-free rate was based on an evaluation of an interest rate that equates to a risk-free interest rate adjusted for the effect of our credit standing.

Warrants. The fair values of the Warrants issued upon the Effective Date were estimated using a Black-Scholes model, a commonly used option-pricing model. The Black-Scholes model was used to estimate the fair value of the warrants with an implied stock price of $20.52; initial exercise price per share of $27.63, $32.13 and $36.18 for Class A, Class B and Class C Warrants, respectively; expected volatility of 58% estimated using volatilities of similar entities; risk-free rate using a 5-year Treasury bond rate; and an expected annual dividend yield which was estimated to be zero.

Condensed Consolidated Balance Sheet

The following consolidated balance sheet is as of February 9, 2021. This consolidated balance sheet includes adjustments that reflect the consummation of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") as well as fair value adjustments as a result of the adoption of fresh start accounting (reflected in the column "Fresh Start Adjustments") as of the Effective Date. The explanatory notes following the table below provide further details on the adjustments, including the assumptions and methods used to determine fair value for its assets, liabilities and warrants.

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Assets						
Current assets:						
Cash and cash equivalents	$ 243	$ (203)	(a)	$ —		$ 40
Restricted cash	—	86	(b)	—		86
Accounts receivable, net	861	(18)	(c)	—		843
Short-term derivative assets	—	—		—		—
Other current assets	66	(5)	(d)	—		61
Total current assets	1,170	(140)		—		1,030
Property and equipment:						
Oil and natural gas properties, successful efforts method						
Proved oil and natural gas properties	25,794	—		(21,108)	(o)	4,686
Unproved properties	1,546	—		(1,063)	(o)	483
Other property and equipment	1,755	—		(1,256)	(o)	499
Total property and equipment	29,095	—		(23,427)	(o)	5,668
Less: Accumulated depreciation, depletion and amortization	(23,877)	—		23,877	(o)	—
Property and equipment held for sale, net	9	—		(7)	(o)	2
Total property and equipment, net	5,227	—		443	(o)	5,670
Other long-term assets	198	—		(84)	(p)	114
Total assets	$ 6,595	$ (140)		$ 359		$ 6,814

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Liabilities and stockholders' equity (deficit)						
Current liabilities:						
Accounts payable	$ 391	$ 24	(e)	$ —		$ 415
Current maturities of long-term debt, net	1,929	(1,929)	(f)	—		—
Accrued interest	4	(4)	(g)	—		—
Short-term derivative liabilities	398	—		—		398
Other current liabilities	645	124	(h)	—		769
Total current liabilities	3,367	(1,785)		—		1,582
Long-term debt, net	—	1,261	(i)	52	(q)	1,313
Long-term derivative liabilities	90	—		—		90
Asset retirement obligations, net of current portion	139	—		97	(r)	236
Other long-term liabilities	5	2	(j)	—		7
Liabilities subject to compromise	9,574	(9,574)	(k)	—		—
Total liabilities	13,175	(10,096)		149		3,228
Contingencies and commitments (Note 7)						
Stockholders' equity (deficit):						
Predecessor preferred stock	1,631	(1,631)	(l)	—		—
Predecessor common stock	—	—		—		—
Predecessor additional paid-in capital	16,940	(16,940)	(l)	—		—
Successor common stock	—	1	(m)	—		1
Successor additional paid-in-capital	—	3,585	(m)	—		3,585
Accumulated other comprehensive income	48	—		(48)	(s)	—
Accumulated deficit	(25,199)	24,941	(n)	258	(t)	—
Total stockholders' equity (deficit)	(6,580)	9,956		210		3,586
Total liabilities and stockholders' equity (deficit)	$ 6,595	$ (140)		$ 359		$ 6,814

Reorganization Adjustments

(a) The table below reflects the sources and uses of cash on the Effective Date from implementation of the Plan:

Sources:		
Proceeds from issuance of the Notes	$	1,000
Proceeds from Rights Offering		600
Proceeds from refunds of interest deposit for the Notes		5
Total sources of cash	$	1,605
Uses:		
Payment of roll-up of DIP Facility balance	$	(1,179)
Payment of Exit Credit Facility - Tranche A Loan		(479)
Transfers to restricted cash for professional fee reserve		(76)
Transfers to restricted cash for convenience claim distribution reserve		(10)
Payment of professional fees		(31)
Payment of DIP Facility interest and fees		(12)
Payment of FLLO alternative transaction fee		(12)
Payment of the Notes fees funded out of escrow		(8)
Payment of RBL interest and fees		(1)
Total uses of cash	$	(1,808)
Net cash used	$	(203)

(b) Represents the transfer of funds to a restricted cash account for purposes of funding the professional fee reserve and the convenience claim distribution reserve.

(c) Reflects the removal of an insurance receivable associated with a discharged legal liability.

(d) Reflects the collection of an interest deposit for the senior unsecured notes.

(e) Changes in accounts payable include the following:

Accrual of professional service provider success fees	$	38
Accrual of convenience claim distribution reserve		10
Accrual of professional service provider fees		5
Reinstatement of accounts payable from liabilities subject to compromise		2
Payment of professional fees		(31)
Net impact to accounts payable	$	24

(f) Reflects payment of the pre-petition credit facility for $1.179 billion and transfer of the Tranche A and Tranche B Loans to long-term debt for $750 million.

(g) Reflect payments of accrued interest and fees on the DIP Facility.

(h) Changes in other current liabilities include the following:

Reinstatement of other current liabilities from liabilities subject to compromise	$	191
Accrual of the Notes fees		2
Settlement of Put Option Premium through issuance of Successor Common Stock		(60)
Payment of DIP Facility fees		(9)
Net impact to other current liabilities	$	124

(i) Changes in long-term debt include the following:

Issuance of the Notes	$	1,000
Issuance of Tranche A and Tranche B Loans		750
Payments on Tranche A Loans		(479)
Debt issuance costs for the Notes		(10)
Net impact to long-term debt, net	$	1,261

(j) Reflects reinstatement of a long-term lease liability.

(k) On the Effective Date, liabilities subject to compromise were settled in accordance with the Plan as follows:

Liabilities subject to compromise pre-emergence	$	9,574
To be reinstated on the Effective Date:		
Accounts payable	$	(2)
Other current liabilities		(191)
Other long-term liabilities		(2)
Total liabilities reinstated	$	(195)
Consideration provided to settle amounts per the Plan or Reorganization:		
Issuance of Successor common stock associated with the Rights Offering and Backstop Commitment and settlement of the Put Option Premium	$	(2,311)
Proceeds from issuance of Successor common stock associated with the Rights Offering and Backstop Commitment		600
Issuance of Successor common stock to FLLO Term Loan holders, incremental to the Rights Offering and Backstop Commitment		(783)
Issuance of Successor common stock to second lien note holders, incremental to the Rights Offering and Backstop Commitment		(124)
Issuance of Successor common stock to unsecured note holders		(45)
Issuance of Successor common stock to general unsecured claims		(8)
Fair value of Class A Warrants		(93)
Fair value of Class B Warrants		(94)
Fair value of Class C Warrants		(68)
Proceeds to holders of general unsecured claims		(10)
Total consideration provided to settle amounts per the Plan	$	(2,936)
Gain on settlement of liabilities subject to compromise	$	6,443

(l) Pursuant to the Plan, as of the Effective Date, all equity interests in Predecessor, including Predecessor's common and preferred stock, were canceled without any distribution.

(m) Reflects the Successor equity including the issuance of 97,907,081 shares of New Common Stock, 11,111,111 shares of Class A Warrants, 12,345,679 shares of Class B Warrants and 9,768,527 shares of Class C Warrants pursuant to the Plan.

Issuance of Successor equity associated with the Rights Offering and Backstop Commitment	$	2,371
Issuance of Successor equity to holders of the FLLO Term Loan, incremental to the Rights Offering and Backstop Commitment		783
Issuance of Successor equity to holders of the Second Lien Notes, incremental to the Rights Offering and Backstop Commitment		124
Issuance of Successor equity to holders of the unsecured senior notes		45
Issuance of Successor equity to holders of allowed general unsecured claims		8
Fair value of Class A warrants		93
Fair value of Class B warrants		94
Fair value of Class C warrants		68
Total change in Successor common stock and additional paid-in capital		3,586
Less: Par value of Successor common stock		(1)
Change in Successor additional paid-in capital	$	3,585

(n) Reflects the cumulative net impact of the effects on accumulated deficit as follows:

Gain on settlement of liabilities subject to compromise	$	6,443
Accrual of professional service provider success fees		(38)
Accrual of professional service provider fees		(5)
Surrender of other receivable		(18)
Payment of FLLO alternative transaction fee		(12)
Total reorganization items, net		6,370
Cancellation of predecessor equity		18,571
Net impact on accumulated deficit	$	24,941

Fresh Start Adjustments

(o) Reflects fair value adjustments to our (i) proved oil and natural gas properties, (ii) unproved properties, (iii) other property and equipment and (iv) property and equipment held for sale, and the elimination of accumulated depletion, depreciation and amortization.

(p) Reflects the fair value adjustment to record historical contracts at their fair values.

(q) Reflects the fair value adjustments to the 2026 Notes and 2029 Notes for $22 million and $30 million, respectively.

(r) Reflects the adjustment to our asset retirement obligations using assumptions as of the Effective Date, including an inflation factor of 2% and an average credit-adjusted risk-free rate of 5.18%.

(s) Reflects the fair value adjustment to eliminate the accumulated other comprehensive income of $9 million related to hedging settlements offset by the elimination of $57 million of income tax effects which has resulted in the recording of an income tax benefit of $57 million. See Note 11 for a discussion of income taxes.

(t) Reflects the net cumulative impact of the fresh start adjustments on accumulated deficit as follows:

Fresh start adjustments to property and equipment	$	443
Fresh start adjustments to other long-term assets		(84)
Fresh start adjustments to long-term debt		(52)
Fresh start adjustments to long-term asset retirement obligations		(97)
Fresh start adjustments to accumulated other comprehensive income		(9)
Total fresh start adjustments impacting reorganizations items, net		201
Income tax effects on accumulated other comprehensive income		57
Net impact to accumulated deficit	$	258

Reorganization Items, Net

We have incurred significant expenses, gains and losses associated with the reorganization, primarily the gain on settlement of liabilities subject to compromise, write-off of unamortized debt issuance costs and related unamortized premiums and discounts, debt and equity financing fees, provision for allowed claims and legal and professional fees incurred subsequent to the Chapter 11 filings for the restructuring process. The accrual for allowed claims primarily represents damages from contract rejections and settlements attributable to the midstream savings requirement as stipulated in the Plan. While the claims reconciliation process is ongoing, we do not believe any existing unresolved claims will result in a material adjustment to the financial statements. The amount of these items, which were incurred in reorganization items, net within our accompanying consolidated statements of operations, have significantly affected our statements of operations.

The following table summarizes the components in reorganization items, net included in our consolidated statements of operations:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Gains on the settlement of liabilities subject to compromise	$ —	$ 6,443	$ 12	$ —
Accrual for allowed claims	—	(1,002)	(879)	—
Write off of unamortized debt premiums (discounts) on Predecessor debt	—	—	518	—
Write off of unamortized debt issuance costs on Predecessor debt	—	—	(61)	—
Gain on fresh start adjustments	—	201	—	—
Gain from release of commitment liabilities	—	55	—	—
Debt and equity financing fees	—	—	(145)	—
Loss on divested assets	—	—	(128)	—
Professional service provider fees and other	—	(60)	(113)	—
Success fees for professional service providers	—	(38)	—	—
Surrender of other receivable	—	(18)	—	—
FLLO alternative transaction fee	—	(12)	—	—
Total reorganization items, net	$ —	$ 5,569	$ (796)	$ —

4. Oil and Natural Gas Property Transactions

Vine Acquisition

On November 1, 2021, we acquired Vine Energy, Inc. ("Vine"), an energy company focused on the development of natural gas properties in the over-pressured stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana pursuant to a definitive agreement with Vine dated August 10, 2021, for total consideration of approximately $1.5 billion, consisting of approximately 18.7 million shares of our common stock and $90 million in cash. In conjunction with the Vine Acquisition, Vine's Second Lien Term Loan was repaid and terminated for $163 million inclusive of a $13 million make whole premium with cash on hand due to the agreement containing a change in control provision making the term loan callable upon closing. Vine's reserve based loan facility, which had no borrowings as of November 1, 2021, was terminated at the time of the acquisition. Additionally, Vine's 6.75% Senior Notes with a principal amount of $950 million were assumed by the Company. See Note 6 for additional discussion of the assumed debt. We funded the cash portion of the consideration with cash on hand.

Preliminary Vine Purchase Price Allocation

We have accounted for the acquisition of Vine as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Vine to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-acquisition contingencies, final tax returns that provide the underlying tax basis of Vine's assets and liabilities and final appraisals of assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

	Preliminary Purchase Price Allocation
Consideration:	
Cash	$ 253
Fair value of Chesapeake's common stock issued in the merger	1,231
Restricted stock unit replacement awards	6
Total consideration	$ 1,490
Fair Value of Liabilities Assumed:	
Current liabilities	$ 765
Long-term debt	1,021
Deferred tax liabilities	49
Other long-term liabilities	272
Amounts attributable to liabilities assumed	$ 2,107
Fair Value of Assets Acquired:	
Cash and cash equivalents	$ 59
Other current assets	206
Proved oil and natural gas properties	2,181
Unproved properties	1,118
Other property and equipment	1
Other long-term assets	32
Amounts attributable to assets acquired	$ 3,597
Total identifiable net assets	$ 1,490

Oil and Natural Gas Properties

For the Vine Acquisition, we applied applicable guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved and unproved oil and natural gas properties as of the acquisition date was based on estimated oil and natural gas reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. We utilized NYMEX strip pricing adjusted for inflation to value the reserves. We then applied various discount rates depending on the classification of reserves and other risk characteristics. Management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired. Additionally, the fair value estimate of proved and unproved oil and natural gas properties was corroborated by utilizing the market approach, which considers recent comparable transactions for similar assets.

The inputs used to value oil and natural gas properties require significant judgment and estimates made by management and represent Level 3 inputs.

Financial Instruments and Other

The fair value measurements of long-term debt were estimated based on a market approach using estimates provided by an independent investment data services firm and represent Level 2 inputs.

Restricted Stock Unit Replacement Awards

Included in consideration for the Vine Acquisition is approximately $6 million related to pre-combination service recognized on Vine's restricted stock unit awards. For restricted stock units that were accelerated or transitioned at the time of the merger, we recognized expense for the portion of the award that was accelerated and included in consideration the portion of the award related to pre-combination service.

Vine Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations oil, natural gas and NGL revenues of $290 million, net gains on oil and natural gas derivatives of $144 million, direct operating expenses of $177 million, including depreciation, depletion and amortization, and other expense of $12 million related to the Vine business for the period from November 1, 2021 to December 31, 2021.

Vine Pro Forma Financial Information

The following unaudited pro forma financial information for the 2021 Successor Period is based on our historical consolidated financial statements adjusted to reflect as if the Vine Acquisition had occurred on February 10, 2021. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including adjustments to conform the classification of expenses in Vine's statements of operations to our classification for similar expenses and the estimated tax impact of pro forma adjustments.

	Successor	
	Period from February 10, 2021 through December 31, 2021	
Revenues	$	5,448
Net income available to common stockholders	$	128
Earnings per common share:		
Basic	$	1.09
Diluted	$	0.97

Mid-Continent Divestiture

On October 13, 2020, we filed a notice with the Bankruptcy Court that we reached an agreement with Tapstone Energy in a Section 363 transaction under the Bankruptcy Code. An auction supervised by the Bankruptcy Court was held on November 10, 2020 in which other pre-qualified buyers submitted bids for the asset. We presented the results of the auction process to the Bankruptcy Court and the sale was approved on November 13, 2020. On December 11, 2020, we closed the transaction with Tapstone Energy for $130 million, subject to post-closing adjustments which resulted in the recognition of a gain of approximately $27 million.

Haynesville Exchange

On November 22, 2020, we filed notice with the Bankruptcy Court that we had reached an agreement with Williams Companies to transfer certain Haynesville assets, including interests in 144 producing wells and approximately 50,000 net acres, in exchange for improved midstream contract terms with respect to assets we retained. On December 15, 2020, the Court approved the transaction with Williams Companies and the exchange resulted in the recognition of loss of approximately $128 million based on the difference between the carrying value of the assets and the fair value of the assets surrendered. The exchange was executed to obtain sufficient savings on midstream obligations as required by the Plan. Therefore, the loss was recorded to reorganization items, net in our consolidated statements of operations.

WildHorse Acquisition

On February 1, 2019, we acquired WildHorse Resource Development Corporation ("WildHorse"), an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas, for approximately 3.6 million shares of our reverse stock split adjusted Predecessor common stock and $381 million in cash. We funded the cash portion of the consideration through borrowings under the pre-petition revolving credit facility. In connection with the closing, we acquired all of WildHorse's debt.

WildHorse Purchase Price Allocation

We have accounted for the acquisition of WildHorse and its corresponding merger with and into our wholly owned subsidiary, Brazos Valley Longhorn, L.L.C. ("Brazos Valley Longhorn" or "BVL"), as a business combination, using the acquisition method. The following table represents the final allocation of the total purchase price of WildHorse to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date.

	Purchase Price Allocation
Consideration:	
Cash	$ 381
Fair value of Chesapeake's common stock issued in the merger	2,037
Total consideration	$ 2,418
Fair Value of Liabilities Assumed:	
Current liabilities	$ 166
Long-term debt	1,379
Deferred tax liabilities	314
Other long-term liabilities	36
Amounts attributable to liabilities assumed	$ 1,895
Fair Value of Assets Acquired:	
Cash and cash equivalents	$ 28
Other current assets	128
Proved oil and natural gas properties	3,264
Unproved properties	756
Other property and equipment	77
Other long-term assets	60
Amounts attributable to assets acquired	$ 4,313
Total identifiable net assets	$ 2,418

Oil and Natural Gas Properties

For the acquisition of WildHorse, we applied applicable guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved and unproved oil and natural gas properties as of the acquisition date was based on estimated oil and natural gas reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. Management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired. Additionally, the fair value estimate of proved and unproved oil and natural gas properties was corroborated by utilizing the market approach which considers recent comparable transactions for similar assets.

The inputs used to value oil and natural gas properties require significant judgment and estimates made by management and represent Level 3 inputs.

Financial Instruments and Other

The fair value measurements of long-term debt were estimated based on a market approach using estimates provided by an independent investment data services firm and represent Level 2 inputs.

WildHorse Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations revenues of $752 million, direct operating expenses of $810 million, including depreciation, depletion and amortization, and other expense of $83 million related to the WildHorse business for the period from February 1, 2019 to December 31, 2019.

WildHorse Pro Forma Financial Information

The following unaudited pro forma financial information for the years ended December 31, 2019 and 2018, respectively, is based on our historical consolidated financial statements adjusted to reflect as if the WildHorse acquisition had occurred on January 1, 2018. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including adjustments to conform the classification of expenses in WildHorse's statements of operations to our classification for similar expenses and the estimated tax impact of pro forma adjustments.

	Predecessor	
	Years Ended December 31,	
	2019	2018
Revenues	$ 8,587	$ 11,211
Net income (loss) available to common stockholders	$ (431)	$ 195
Earnings (loss) per common share:		
Basic	$ (51.77)	$ 42.89
Diluted	$ (51.77)	$ 42.89

This unaudited pro forma information has been derived from historical information. The unaudited pro forma financial information is not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the periods presented, nor is it necessarily indicative of future results.

2019 Transactions

In 2019, we received proceeds of approximately $130 million, net of post-closing adjustments, and recognized a gain of approximately $46 million, primarily for the sale of non-core oil and natural gas properties.

5. Earnings Per Share

Basic earnings (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities during the Successor Period consist of issuable shares related to warrants, unvested restricted stock units, and unvested performance share units and during the Predecessor Period have historically consisted of unvested restricted stock, contingently issuable shares related to preferred stock and convertible senior notes unless their effect was antidilutive.

The reconciliations between basic and diluted earnings (loss) per share are as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Numerator				
Net income (loss), basic and diluted	$ 945	$ 5,383	$ (9,756)	$ (416)
Denominator (in thousands)				
Weighted average common shares outstanding, basic	101,754	9,781	9,773	8,325
Effect of potentially dilutive securities				
Preferred stock	—	290	—	—
Warrants	14,376	—	—	—
Restricted stock	200	—	—	—
Performance share units	11	—	—	—
Weighted average common shares outstanding, diluted	116,341	10,071	9,773	8,325
Earnings (loss) per common share				
Earnings (loss) per common share, basic	$ 9.29	$ 550.35	$ (998.26)	$ (49.97)
Earnings (loss) per common share, diluted	$ 8.12	$ 534.51	$ (998.26)	$ (49.97)

Successor

During the 2021 Successor Period, the diluted earnings (loss) per share calculation excludes the effect of 1,228,828 reserved shares of common stock and 2,318,446 reserved Class C Warrants related to the settlement of General Unsecured Claims associated with the Chapter 11 Cases as all necessary conditions had not been met to be considered dilutive shares for the 2021 Successor Period.

Predecessor

The diluted earnings (loss) per share calculation for the 2020 Predecessor Period excludes the antidilutive effect of 290,716 shares of common stock equivalent of our preferred stock.

The diluted earnings (loss) per share calculation for the 2019 Predecessor Period excludes the antidilutive effect of 295,731 shares of common stock equivalent of our preferred stock and 2,210 shares of restricted stock.

We had the option to settle conversions of the 5.50% convertible senior notes due 2026 with cash, shares or common stock or any combination thereof. As the price of our common stock was below the conversion threshold level for any time during the conversion period, there was no impact to diluted earnings (loss) per share.

6. Debt

Our long-term debt consisted of the following as of December 31, 2021 and 2020:

	Successor		Predecessor	
	December 31, 2021		December 31, 2020	
	Carrying Amount	Fair Value[a]	Carrying Amount	Fair Value[a]
Exit Credit Facility - Tranche A Loans	$ —	$ —	$ —	$ —
Exit Credit Facility - Tranche B Loans	221	221	—	—
5.50% senior notes due 2026	500	526	—	—
5.875% senior notes due 2029	500	535	—	—
6.75% senior notes due 2029[b]	950	1,031	—	—
DIP Facility	—	—	—	—
Pre-petition revolving credit facility	—	—	1,929	1,929
Term loan due 2024	—	—	1,500	1,220
11.50% senior secured second lien notes due 2025	—	—	2,330	373
6.625% senior notes due 2020	—	—	176	8
6.875% senior notes due 2020	—	—	73	3
6.125% senior notes due 2021	—	—	167	7
5.375% senior notes due 2021	—	—	127	5
4.875% senior notes due 2022	—	—	272	12
5.75% senior notes due 2023	—	—	167	8
7.00% senior notes due 2024	—	—	624	29
6.875% senior notes due 2025	—	—	2	2
8.00% senior notes due 2025	—	—	246	10
5.50% convertible senior notes due 2026	—	—	1,064	42
7.50% senior notes due 2026	—	—	119	5
8.00% senior notes due 2026	—	—	46	2
8.00% senior notes due 2027	—	—	253	11
Premiums on senior notes	116	—	—	—
Debt issuance costs	(9)	—	—	—
Total debt, net	2,278	2,313	9,095	3,666
Less current maturities of long-term debt, net	—	—	(1,929)	(1,929)
Less amounts reclassified to liabilities subject to compromise	—	—	(7,166)	(1,737)
Total long-term debt, net	$ 2,278	$ 2,313	$ —	$ —

(a) The carrying value of borrowings under our Exit Credit Facility approximate fair value as the interest rates are based on prevailing market rates; therefore, they are a Level 1 fair value measurement. For all other debt, a market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value.

(b) On November 1, 2021, we acquired the debt of Vine, which consisted of 6.75% senior notes due 2029. See further discussion below.

Successor Debt

Our post-emergence exit financing consists of the Exit Credit Facility, which includes a reserve-based revolving credit facility and a non-revolving loan facility, and the Notes.

Exit Credit Facility. On the Effective Date, pursuant to the terms of the Plan, the Company, as borrower, entered into a reserve-based credit agreement (the “Credit Agreement”) providing for a reserve-based credit facility with an initial borrowing base of $2.5 billion. The borrowing base will be redetermined semiannually on or around May 1 and November 1 of each year. Our borrowing base was reaffirmed in October 2021, and the next scheduled redetermination will be on or about May 1, 2022. The aggregate initial elected commitments of the lenders under the Exit Credit Facility were $1.75 billion of Tranche A Loans and $221 million of fully funded Tranche B Loans.

The Exit Credit Facility provides for a $200 million sublimit of the aggregate commitments that are available for the issuance of letters of credit. The Exit Credit Facility bears interest at the ABR (alternate base rate) or LIBOR, at our election, plus an applicable margin (ranging from 2.25–3.25% per annum for ABR loans and 3.25–4.25% per annum for LIBOR loans, subject to a 1.00% LIBOR floor), depending on the percentage of the borrowing base then being utilized. The Tranche A Loans mature three years after the Effective Date and the Tranche B Loans mature four years after the Effective Date. The Tranche B Loans can be repaid if no Tranche A Loans are outstanding.

The Credit Agreement contains financial covenants that require the Company and its guarantors, on a consolidated basis, to maintain (i) a first lien leverage ratio of not more than 2.75 to 1:00, (ii) a total leverage ratio of not more than 3.50 to 1:00, (iii) a current ratio of not less than 1.00 to 1:00 and (iv) at any time additional secured debt is outstanding, an asset coverage ratio of not less than 1.50 to 1:00, defined as PV10 of PDP reserves to total secured debt. The Company has no additional secured debt outstanding as of December 31, 2021.

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

The Company is required to pay a commitment fee of 0.50% per annum on the average daily unused portion of the current aggregate commitments under the Tranche A Loans. The Company is also required to pay customary letter of credit and fronting fees.

Outstanding Senior Notes. On February 2, 2021, Chesapeake Escrow Issuer LLC, then an indirect wholly owned subsidiary of the Company, issued $500 million aggregate principal amount of its 2026 Notes and $500 million aggregate principal amount of its 2029 Notes. The Notes included a $52 million premium to reflect fair value adjustments at the date of emergence.

The Notes are guaranteed on a senior unsecured basis by each of the Company’s subsidiaries that guarantee the Exit Credit Facility.

The Notes were issued pursuant to an indenture, dated as of February 5, 2021, among the Issuer, the Guarantors and Deutsche Bank Trust Company Americas, as trustee.

Interest on the Notes is payable semi-annually, on February 1 and August 1 of each year, commencing on August 1, 2021, to holders of record on the immediately preceding January 15 and July 15.

The Notes are the Company’s senior unsecured obligations. Accordingly, they rank (i) equal in right of payment to all existing and future senior indebtedness, including borrowings under the Exit Credit Facility, (ii) effectively subordinate in right of payment to all of existing and future secured indebtedness, including indebtedness under the Exit Credit Facility, to the extent of the value of the collateral securing such indebtedness, (iii) structurally subordinate in right of payment to all existing and future indebtedness and other liabilities of any future subsidiaries that do not guarantee the Notes and any entity that is not a subsidiary that does not guarantee the Notes and (iv) senior in right of payment to all future subordinated indebtedness. Each guarantee of the Notes by a guarantor is a general, unsecured, senior obligation of such guarantor. Accordingly, the guarantees (i) rank equally in right of payment with all existing and future senior indebtedness of such guarantor (including such guarantor’s guarantee of indebtedness under the Exit Credit Facility), (ii) are subordinated to all existing and future secured indebtedness of such guarantor, including such guarantor's guarantee of indebtedness under our Exit Credit Facility, to the extent of the value of the collateral of such guarantor securing such secured indebtedness, (iii) are structurally subordinated to all indebtedness and other liabilities of any future subsidiaries of such guarantor that do not guarantee the notes and (iv) rank senior in right of payment to all future subordinated indebtedness of such guarantor.

Vine Senior Notes

As a result of the completion of the Vine Acquisition, the Company and certain of its subsidiaries entered into a supplemental indenture pursuant to which the Company assumed the obligations under Vine's $950 million aggregate principal amount of 6.75% senior notes due 2029 (the "Vine Notes") issued under the indenture dated April 7, 2021 with Wilmington Trust, National Association, as Trustee (the "Vine Indenture"). The Vine Notes included a $71 million premium to reflect fair value adjustments at the date of acquisition.

The Company and certain of its subsidiaries have agreed to guarantee such obligations under the Vine Indenture. Additionally, certain subsidiaries of Vine entered into a supplemental indenture to the Company's existing indenture, dated February 5, 2021 with Deutsche Bank Trust Company Americas as trustee (the "CHK Indenture"), pursuant to which such subsidiaries of Vine have agreed to guarantee obligations under the CHK Indenture.

Interest on the Vine Notes is payable semi-annually, on April 15 and October 15 of each year to holders of record on the immediately preceding April 1 and October 1. Our first interest payment will be on April 15, 2022.

Phase-Out of LIBOR

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848)*. The purpose of ASU 2020-04 is to provide optional guidance to ease the potential effects on financial reporting of the market-wide migration away from Interbank Offered Rates such as LIBOR, which is no longer being used on new loans as of December 31, 2021, to alternative reference rates. ASU 2020-04 applies only to contracts, hedging relationships, debt arrangements and other transactions that reference a benchmark reference rate expected to be discontinued because of reference rate reform. The amendments in ASU 2020-04 are effective for all entities as of March 12, 2020 through December 31, 2022. The adoption of this guidance will not have a material impact on our consolidated financial statements and related disclosures.

Chapter 11 Proceedings - Predecessor Debt

Filing of the Chapter 11 Cases constituted an event of default with respect to certain of our previous secured and unsecured debt obligations. As a result of the Chapter 11 Cases, the principal and interest due under these debt instruments became immediately due and payable. However, Section 362 of the Bankruptcy Code stayed the creditors from taking any action as a result of the default.

The principal amounts outstanding under the FLLO Term Loan, Second Lien Notes and all of our other unsecured senior and convertible senior notes were reclassified as liabilities subject to compromise on the accompanying consolidated balance sheet as of December 31, 2020.

The agreements for our FLLO Term Loan, Second Lien Notes, and unsecured senior and convertible senior notes contained provisions regarding the calculation of interest upon default. Upon default, the interest rate on the FLLO Term Loan increased from LIBOR plus 8.00% to alternative base rate (ABR) (3.25% during the fourth quarter of the 2020 Predecessor Period) plus Applicable Margin (7.00% during the fourth quarter of the 2020 Predecessor Period) plus 2.00%. For the Second Lien Notes and all of our other unsecured senior and convertible senior notes, the interest rate remained the same upon default. However, interest accrued on the amount of unpaid interest in addition to the principal balance. We did not pay or recognize interest on the FLLO Term Loan, Second Lien Notes, or unsecured senior and convertible senior notes during the Chapter 11 process.

Debtor-in-Possession Credit Agreement

On June 28, 2020, prior to the commencement of Chapter 11 Cases, the Company entered into a commitment letter with certain of the lenders ("New Money Lenders") under the pre-petition revolving credit facility and/or their affiliates to provide the Debtors with a debtor-in-possession credit agreement in an aggregate principal amount of up to approximately $2.104 billion in commitments and loans from the New Money Lenders. The DIP Facility consisted of a revolving loan facility of new money in an aggregate principal amount of up to $925 million, which included a sub-facility of up to $200 million for the issuance of letters of credit, and a $1.179 billion term loan that reflected the roll-up of a portion of outstanding borrowings under the pre-petition revolving credit facility: (i) a $925 million term loan reflected the roll-up of a portion of outstanding existing borrowings made by the New Money Lenders under the existing revolving credit agreement and (ii) an up to approximately $254 million term loan reflected the roll-up or a portion of outstanding existing borrowings made by certain other lenders under the pre-petition revolving credit facility agreement. The $750 million of outstanding borrowings under the pre-petition revolving credit facility that were not rolled up remained outstanding throughout the Chapter 11 Cases but accrued interest at a lower rate than the rolled-up loans. The proceeds of the DIP Facility were used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases, payment of court approved adequate protection obligations and other such purposes consistent with the DIP Facility. On the Effective Date, the DIP Facility was terminated and the holders of obligations under the DIP Facility received payment in full in cash; provided that to the extent such lender under the DIP Facility was also a lender under the Exit Credit Facility, such lender's allowed DIP claims were first reduced dollar-for-dollar and satisfied by the amount of its Exit RBL Loans provided as of the Effective Date.

Predecessor Debt Issuances and Retirements 2020

In the 2020 Predecessor Period, we repurchased approximately $160 million aggregate principal amount of the following senior notes for $95 million and recorded an aggregate gain of approximately $65 million.

	Notes Repurchased
6.625% senior notes due 2020	$ 32
6.875% senior notes due 2020	20
4.875% senior notes due 2022	66
5.75% senior notes due 2023	42
Total	$ 160

Predecessor Debt 2019

In December 2019, we entered into a secured 4.5-year term loan facility in an aggregate principal amount of $1.5 billion for net proceeds of approximately $1.455 billion. We used the net proceeds to finance tender offers for our unsecured BVL senior notes and to repay amounts outstanding under our BVL revolving credit facility. We recorded an aggregate net gain of approximately $4 million associated with the retirement of our BVL senior notes and the BVL revolving credit facility.

We privately negotiated exchanges of approximately $507 million principal amount of our outstanding senior notes for 235,563,519 shares of common stock and $186 million principal amount of our outstanding convertible senior notes for 73,389,094 shares of common stock. We recorded an aggregate net gain of approximately $64 million associated with the exchanges.

Pre-Petition Revolving Credit Facility

Our pre-petition revolving credit facility was scheduled to mature in September 2023 and the aggregate commitment of the lenders and borrowing base under the facility was $3.0 billion. The pre-petition revolving credit facility provided for an accordion feature, pursuant to which the aggregate commitments thereunder may be increased to up to $4.0 billion from time to time, subject to agreement of the participating lenders and certain other customary conditions. As of December 31, 2020, we had outstanding borrowings of $1.929 billion under our pre-petition revolving credit facility and had used $54 million for various letters of credit.

Borrowings under our pre-petition revolving credit facility bore interest at an alternative base rate (ABR) or LIBOR, at our election, plus an applicable margin ranging from 1.50%-2.50% per annum for ABR loans and 2.50%-3.50% per annum for LIBOR loans, depending on the percentage of the borrowing base then being utilized.

Our pre-petition revolving credit facility was subject to various financial and other covenants. The terms of the pre-petition revolving credit facility included covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, incur liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates.

7. Contingencies and Commitments

Contingencies

Chapter 11 Proceedings

Commencement of the Chapter 11 Cases automatically stayed the proceedings and actions against us that are described below, in addition to actions seeking to collect pre-petition indebtedness or to exercise control over the property of the Company's bankruptcy estates. The Plan in the Chapter 11 Cases, which became effective on February 9, 2021, provided for the treatment of claims against the Company's bankruptcy estates, including pre-petition liabilities that had not been satisfied or addressed during the Chapter 11 Cases. See Note 2 for additional information.

Litigation and Regulatory Proceedings

We were involved in a number of litigation and regulatory proceedings as of the Petition Date. Many of these proceedings were in early stages, and many of them sought damages and penalties, the amount of which is indeterminate. Our total accrued liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

We are involved in, and expect to continue to be involved in, various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. The majority of the prepetition legal proceedings have been settled during the Chapter 11 Cases or will be resolved in connection with the claims reconciliation process before the Bankruptcy Court. Any allowed claim related to such prepetition litigation will be treated in accordance with the Plan.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

We were recently dismissed as a defendant from numerous lawsuits in Oklahoma alleging that we and other companies engaged in activities that have caused earthquakes. The lawsuits sought compensation for injury to real and personal property, diminution of property value, economic losses due to business interruption, interference with the use and enjoyment of property, annoyance and inconvenience, personal injury and emotional distress. In addition, they sought the reimbursement of insurance premiums and the award of punitive damages, attorneys' fees, costs, expenses and interest. Any allowed claim related to such prepetition litigation will be treated in accordance with the Plan.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Commitments

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of oil, natural gas and NGL to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, they are reflected in our estimates of proved reserves.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below:

	Successor
	December 31, 2021
2022	$ 564
2023	500
2024	459
2025	356
2026	318
2027 – 2036	1,631
Total	$ 3,828

In addition, we have long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually, or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees may vary with the applicable agreement.

Other Commitments

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging for, financial or performance assurances to third parties on behalf of our wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with acquisitions and divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party and/or other specified matters. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of entering into or consummating a particular transaction. For divestitures of oil and natural gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title or environmental defects.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

8. Other Liabilities

Other current liabilities as of December 31, 2021 and 2020 are detailed below:

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Revenues and royalties due others	$ 617	$ 236
Accrued drilling and production costs	142	104
Accrued hedging costs	113	7
Accrued compensation and benefits	91	59
Other accrued taxes	86	82
Operating leases	29	24
Joint interest prepayments received	14	8
Debt and equity financing fees	—	69
Other	110	134
Total other current liabilities	$ 1,202	$ 723

9. Leases

We are a lessee under various agreements for drilling rigs, compressors, vehicles, office space and gas treating plants. As of December 31, 2021, these leases have remaining terms ranging from one month to three years. Certain of our lease agreements include options to renew the lease, terminate the lease early or purchase the underlying asset at the end of the lease. We determine the lease term at the lease commencement date as the non-cancelable period of the lease, including options to extend or terminate the lease when we are reasonably certain to exercise the option. The company's vehicles are the only leases with renewal options that we are reasonably certain to exercise. The renewals are reflected in the ROU asset and lease liability balances.

Our operating ROU assets are included in other long-term assets while operating lease liabilities are included in other current and other long-term liabilities on the consolidated balance sheet. Finance ROU assets are reflected in total property and equipment, net, while finance lease liabilities are included in other current and other long-term liabilities on the consolidated balance sheet.

On November 1, 2021, we acquired Vine and, as part of the purchase price allocation, we recognized additional operating lease liabilities of $32 million and a related ROU asset of $32 million related to drilling rig leases, an office space lease and gas treating plant leases.

On February 1, 2019, we acquired WildHorse and, as part of the purchase price allocation, we recognized additional operating lease liabilities of $40 million, a related ROU asset of $38 million, and lease incentives of $2 million related to two office space leases, a long-term hydraulic fracturing agreement and other equipment leases. Regarding our long-term hydraulic fracturing agreements, we made a policy election to treat both lease and non-lease components as a single lease component. All of these acquired leases were approved for rejection during our bankruptcy process and subsequently removed from our balance sheet.

In 2018, we sold our wholly owned subsidiary, Midcon Compression, L.L.C., to a third party and subsequently leased back certain natural gas compressors for 38 months. The lease was accounted for as a finance lease liability until the contract was renegotiated as part of our bankruptcy process and the changes to the contract resulted in the reclassification of the finance lease as an operating lease in March 2021.

The following table presents our ROU assets and lease liabilities as of December 31, 2021 and 2020.

	Successor		Predecessor	
	December 31, 2021		December 31, 2020	
	Finance	Operating	Finance	Operating
ROU assets	$ —	$ 38	$ 9	$ 29
Lease liabilities:				
Current lease liabilities	$ —	$ 29	$ 9	$ 27
Long-term lease liabilities	—	9	—	2
Total lease liabilities	—	38	9	29
Less amounts reclassified to liabilities subject to compromise	—	—	(9)	(5)
Total lease liabilities, net	$ —	$ 38	$ —	$ 24

Additional information for the Company’s operating and finance leases is presented below:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Lease cost:				
Amortization of ROU assets	$ —	$ 1	$ 9	$ 8
Interest on lease liability	—	—	1	2
Finance lease cost	—	1	10	10
Operating lease cost	33	3	17	26
Short-term lease cost	13	—	32	112
Total lease cost	$ 46	$ 4	$ 59	$ 148
Other information:				
Operating cash outflows from finance lease	$ —	$ —	$ 1	$ 2
Operating cash outflows from operating leases	$ 7	$ —	$ 9	$ 11
Investing cash outflows from operating leases	$ 39	$ 3	$ 40	$ 127
Financing cash outflows from finance lease	$ —	$ 1	$ 9	$ 8

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Weighted average remaining lease term - finance lease	N/A	1.00 year
Weighted average remaining lease term - operating leases	1.44 years	1.12 years
Weighted average discount rate - finance lease	N/A	7.50 %
Weighted average discount rate - operating leases	3.80 %	6.46 %

Maturity analysis of operating lease liabilities are presented below:

	Successor
	December 31, 2021
2022	$ 29
2023	8
2024	1
Total lease payments	38
Less imputed interest	—
Present value of lease liabilities	38
Less current maturities	(29)
Present value of lease liabilities, less current maturities	$ 9

10. Revenue Recognition

The following table shows revenue disaggregated by operating area and product type, for the periods presented:

	Successor			
	Period from February 10, 2021 through December 31, 2021			
	Oil	Natural Gas	NGL	Total
Marcellus	$ —	$ 1,370	$ —	$ 1,370
Haynesville	—	998	—	998
Eagle Ford	1,354	179	179	1,712
Powder River Basin	202	75	44	321
Oil, natural gas and NGL revenue	$ 1,556	$ 2,622	$ 223	$ 4,401
Marketing revenue	$ 1,158	$ 908	$ 197	$ 2,263

	Predecessor			
	Period from January 1, 2021 through February 9, 2021			
	Oil	Natural Gas	NGL	Total
Marcellus	$ —	$ 119	$ —	$ 119
Haynesville	—	53	—	53
Eagle Ford	159	17	17	193
Powder River Basin	20	7	6	33
Oil, natural gas and NGL revenue	$ 179	$ 196	$ 23	$ 398
Marketing revenue	$ 141	$ 78	$ 20	$ 239
	Year Ended December 31, 2020			
	Oil	Natural Gas	NGL	Total
Marcellus	$ —	$ 631	$ —	$ 631
Haynesville	—	362	—	362
Eagle Ford	1,202	129	97	1,428
Powder River Basin	170	41	20	231
Mid-Continent	55	25	13	93
Oil, natural gas and NGL revenue	$ 1,427	$ 1,188	$ 130	$ 2,745
Marketing revenue from contracts with customers	$ 1,195	$ 494	$ 110	$ 1,799
Other marketing revenue	67	3	—	70
Marketing revenue	$ 1,262	$ 497	$ 110	$ 1,869

	Year Ended December 31, 2019			
	Oil	Natural Gas	NGL	Total
Marcellus	$ —	$ 856	$ —	$ 856
Haynesville	—	620	—	620
Eagle Ford	2,010	185	135	2,330
Powder River Basin	369	77	32	478
Mid-Continent	164	44	25	233
Oil, natural gas and NGL revenue	$ 2,543	$ 1,782	$ 192	$ 4,517
Marketing revenue from contracts with customers	$ 2,473	$ 900	$ 246	$ 3,619
Other marketing revenue	311	41	—	352
Losses on marketing derivatives	—	(4)	—	(4)
Marketing revenue	$ 2,784	$ 937	$ 246	$ 3,967

Accounts Receivable

Accounts receivable as of December 31, 2021 and 2020 are detailed below:

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Oil, natural gas and NGL sales	$ 922	$ 589
Joint interest billings	158	119
Other	38	68
Allowance for doubtful accounts	(3)	(30)
Total accounts receivable, net	$ 1,115	$ 746

11. Income Taxes

The components of the income tax expense (benefit) for each of the periods presented below are as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Current				
Federal	$ —	$ —	$ (3)	$ —
State	—	—	(6)	(26)
Current Income Taxes	—	—	(9)	(26)
Deferred				
Federal	(45)	(54)	—	(297)
State	(4)	(3)	(10)	(8)
Deferred Income Taxes	(49)	(57)	(10)	(305)
Total	$ (49)	$ (57)	$ (19)	$ (331)

The income tax expense (benefit) reported in our consolidated statement of operations is different from the federal income tax expense (benefit) computed using the federal statutory rate for the following reasons:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Income tax expense (benefit) at the federal statutory rate of 21%	$ 188	$ 1,119	$ (2,051)	$ (134)
State income taxes (net of federal income tax benefit)	(86)	238	(41)	(21)
Partial release of valuation allowance due to Acquisitions	(49)	—	—	(314)
Change in valuation allowance excluding impact of Acquisitions	(179)	(1,191)	2,010	114
Reorganization items	60	(173)	41	—
Transaction costs	11	—	—	—
Removal of stranded tax effects in accumulated other comprehensive income	—	(57)	—	—
Equity-based compensation (non-officer)	—	7	10	4
Officer compensation limited under Section 162(m)	2	—	9	3
Other	4	—	3	17
Total	$ (49)	$ (57)	$ (19)	$ (331)

After taking into account the effect of the Vine Acquisition, we have increased our estimate of state apportionment to Louisiana. This results in a shift of our state profile towards a higher overall state tax rate, and as such our deferred tax assets associated with that state have increased resulting in a deferred tax benefit in our state tax provision. Such increase was offset in full by an increase to our valuation allowance. We recognize certain permanent book-to-tax differences relating to reorganization items such as differences in the treatment of the extinguishment of liabilities, differences due to the non-deductibility of certain expenses associated with administering the plan of reorganization, and the adjustment to deferred tax assets which are subject to expiration before they are utilizable. In the Successor Period, we recognized a difference due to the non-deductibility of certain transaction costs and other post-combination expenses.

We reassessed the realizability of our deferred tax assets and continue to maintain a full valuation allowance against our net deferred tax asset positions for federal and state purposes. Of the net decrease in our valuation allowance, $1.191 billion is reflected as a component of income tax benefit in our consolidated statement of operations for the 2021 Predecessor Period, and $228 million is reflected as a component of income tax benefit in our consolidated statement of operations for the 2021 Successor Period.

Deferred income taxes are provided to reflect temporary differences in the tax basis of assets and liabilities and their reported amounts in the financial statements. The tax-effected temporary differences, net operating loss ("NOL") carryforwards and excess business interest expense carryforwards that comprise our deferred income taxes are as follows:

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Deferred tax liabilities:		
Other	$ (3)	$ (3)
Deferred tax liabilities	(3)	(3)
Deferred tax assets:		
Property, plant and equipment	340	907
Net operating loss carryforwards	784	2,066
Carrying value of debt	31	48
Excess business interest expense carryforward	684	293
Asset retirement obligations	86	34
Investments	66	71
Accrued liabilities	38	288
Derivative instruments	289	53
Other	68	51
Deferred tax assets	2,386	3,811
Valuation allowance	(2,383)	(3,808)
Deferred tax assets after valuation allowance	3	3
Net deferred tax liability	$ —	$ —

As of December 31, 2021, and 2020, we had deferred tax assets of $2.386 billion and $3.811 billion upon which we had a valuation allowance of $2.383 billion and $3.808 billion, respectively. Of the net change in the valuation allowance of $1.425 billion for both federal and state deferred tax assets, $1.419 billion is reflected as a component of income tax benefit in the consolidated statement of operations and the difference is reflected in components of stockholders' equity.

A valuation allowance against deferred tax assets, including NOL carryforwards and disallowed business interest carryforwards, is recognized when it is more likely than not that all or some portion of the benefit from the deferred tax assets will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of existing taxable temporary differences, tax planning strategies, as well as the current and forecasted business economics of our industry. Management assesses all available evidence, both positive and negative, to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. Based on all available positive and negative evidence, including projections of future taxable income, we believe it is more likely than not that our deferred tax assets will not be realized. As such, a full valuation allowance was recorded against our net deferred tax asset position for federal and state purposes. A significant piece of objectively verifiable negative evidence consists of the losses incurred in prior quarters. The current quarter’s pre-tax book income is a source of positive evidence, however given the absence of a trend of multiple successive quarters with book income, such evidence does not outweigh the negative evidence. Should future results of operations demonstrate a trend of profitability, additional weight may be placed upon other evidence, such as future forecasts of taxable income. Additionally, future events and new evidence, such as the integration of and realization of profit from the recently acquired assets could lead to increased weight being placed upon future forecasts and the conclusion that some or all of the deferred tax assets are more likely than not to be realizable. Therefore, we believe that there is a possibility that some or all of the valuation allowance could be released in the foreseeable future.

Our ability to utilize NOL carryforwards, disallowed business interest carryforwards, tax credits and possibly other tax attributes to reduce future taxable income and federal income tax is subject to various limitations under Section 382 of the Code. The utilization of such attributes may be subject to an annual limitation under Section 382 of the Code should transactions involving our equity result in a cumulative shift of more than 50% in the beneficial ownership of our stock during any three-year testing period (an “Ownership Change”).

As a result of emergence from bankruptcy on February 9, 2021, the Company did experience an Ownership Change. We did not qualify for the exception under Section 382(l)(5) of the Code, and therefore an annual limitation was determined under Section 382(l)(6) of the Code, which is based on the post-emergence value of our equity multiplied by the adjusted federal long-term rate in effect for the month in which the ownership change occurred. The amount of the annual limitation has been computed to be $54 million and was prorated for the 2021 tax year based on the number of days attributable to the post-Effective Date portion of the year. The limitation applies to our NOL carryforwards, disallowed business interest carryforwards and general business credits until such attributes expire or are fully utilized. As we believe we were in an overall net unrealized built-in loss position at the Effective Date, the limitation also applies to any recognized built-in losses incurred for a period of five years but only to the extent of the overall net unrealized built-in loss. Recognized built-in losses incurred during 2021 include a portion of our tax depreciation, depletion, and amortization deductions along with a portion of our realized hedging losses. We have incurred enough of those items for the 2021 tax year and have thus disallowed deductions up to the net unrealized built-in loss. Accordingly, we estimate no further restriction on the company’s deduction for such items. Some states impose similar limitations on tax attribute utilization upon experiencing an Ownership Change.

In Chapter 11 bankruptcy cases, the cancellation of debt income (“CODI”) realized upon emergence from bankruptcy is excludible from taxable income but results in a reduction of tax attributes in accordance with the attribute reduction and ordering rules of Section 108 of the Code. The amount of our CODI is estimated to be $5 billion, all of which will reduce our NOL carryforwards. This attribute reduction occurs after the close of the tax year, however we have included the estimated effect of such reduction in our ending deferred tax assets as of December 31, 2021. As a result of the Section 382 limitation, $593 million of federal NOLs remaining after the CODI reduction are estimated to expire before they would become utilizable and as such have been removed from our deferred tax assets. The states we operate in generally have similar rules for attribute reduction and Section 382 limitation which results in the reduction of certain of our state NOL carryforwards.

On November 1, 2021, we completed the acquisition of Vine. For federal income tax purposes, the transaction qualified as a tax-free merger under Section 368 of the Code and, as a result, we acquired carryover tax basis in Vine’s assets and liabilities. A net deferred tax liability of $49 million determined through business combination accounting includes deferred tax liabilities on plant, property and equipment totaling $298 million, partially offset by deferred tax assets totaling $249 million relating to federal NOL carryforwards, disallowed business interest carryforwards and certain other deferred tax assets. These carryforwards are subject to a base annual Section 382 limitation of approximately $2 million. The base annual limitation is estimated to be increased over the first five years for recognized built-in gains of approximately $14 million per year. We determined that no separate valuation allowances were required to be established against any of the individual deferred tax assets acquired. We determined that the acquired deferred tax liability was a source of evidence to release valuation allowance, and as such $49 million was recorded as a tax benefit in the successor period.

As of December 31, 2021, and after taking into account each of the foregoing matters, the federal NOLs and excess business interest attributes are as follows:

	Attributes subject to Section 382 base annual limitation		Attributes not subject to Section 382 limitation
	$54 million	$2 million	
Net operating losses, by year of expiration:			
2037	$ 858	$ 10	$ —
Indefinitely lived	1,919	112	—
Total federal net operating losses	$ 2,777	$ 122	$ —
Excess business interest expense (indefinitely lived)	$ 1,455	$ 58	$ 1,459

We had state NOL carryforwards of approximately $3.541 billion. Several states adopt the federal NOL carryforward period such that our more recent state NOLs do not expire. The state NOL carryforwards are subject to apportioned amounts of the federal Section 382 limitations.

Accounting guidance for recognizing and measuring uncertain tax positions requires a more likely than not threshold condition be met on a tax position, based solely on the technical merits of being sustained, before any benefit of the tax position can be recognized in the financial statements. Guidance is also provided regarding recognition, classification and disclosure of uncertain tax positions. As of both December 31, 2021, and 2020, the amount of unrecognized tax benefits related to NOL carryforwards and tax liabilities associated with uncertain tax positions was $74 million, of which, as of both December 31, 2021 and December 31, 2020, $29 million is related to state tax receivables not expected to be recovered and the remainder is related to NOL carryforwards. If recognized, $29 million of the uncertain tax positions identified would have an effect on the effective tax rate. As of December 31, 2021, and 2020, we had no amounts accrued for interest related to these uncertain tax positions. We recognize interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. $24 million of the state tax receivable relates to claims for refund of Pennsylvania income taxes. During the fourth quarter of 2021, a court case with similar claims as ours was decided in favor of the taxpayer. We have considered this new information and determined that we have no change to our assessment of the recognition and measurement of our position. Should the state exhaust its appeals so that the taxpayer ultimately prevails we may be successful in applying that precedent to our claims. As such, it is possible that we may reassess that refund claim in the next twelve months and ascertain it to be more likely than not to be sustained. Should this occur, we will record a current tax benefit and income tax receivable for the amount we determine we are likely to sustain.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Unrecognized tax benefits at beginning of period	$ 74	$ 74	$ 74	$ 79
Additions based on tax positions related to the current year	—	—	—	—
Additions to tax positions of prior years	—	—	—	27
Settlements	—	—	—	(32)
Expiration of the applicable statute of limitations	—	—	—	—
Reductions to tax positions of prior years	—	—	—	—
Unrecognized tax benefits at end of period	$ 74	$ 74	$ 74	$ 74

Our federal and state income tax returns are subject to examination by federal and state tax authorities. Notification was received from the IRS during February 2021 that the examination of the WildHorse 2017 federal income tax return has been closed as a no-change audit. Our tax years 2018 through 2021 remain open for all purposes of examination by the IRS as do the WildHorse 2018 federal income tax return and the WildHorse short period return for January 1, 2019, through February 1, 2019. However, certain earlier tax years remain open for adjustment to the extent of their NOL carryforwards available for future utilization.

In addition, tax years 2018 through 2021 as well as certain earlier years remain open for examination by state tax authorities. Currently, several state examinations are in progress of various years. We do not anticipate that the outcome of any federal or state audit will have a significant impact on our financial position or results of operations.

12. Equity

New Common Stock.

As discussed in Note 2, on the Effective Date, we issued an aggregate of 97,907,081 shares of New Common Stock, par value $0.01 per share, to the holders of allowed claims, and approximately 2,092,918 shares of New Common Stock were reserved for future distributions under the Plan. During the 2021 Successor Period, 864,090 reserved shares were issued to resolve allowed unsecured claims.

As discussed in Note 4, on November 1, 2021, we acquired Vine and issued 18,709,399 shares of New Common Stock.

Dividends

In the 2021 Successor Period, we initiated a new annual dividend on our common shares, expected to be paid quarterly. The following table summarizes our dividend payments in the 2021 Successor Period:

Payment Date	Stockholders of Record Date	Dividend Payment		Rate Per Share	
June 10, 2021	May 24, 2021	$	34	$	0.34375
September 9, 2021	August 24, 2021		33	$	0.34375
December 9, 2021	November 24, 2021		52	$	0.43750
Total dividends paid		$	119		

Warrants

	Class A Warrants	Class B Warrants	Class C Warrants[(a)]
Issued as of February 10, 2021	11,111,111	12,345,679	9,768,527
Converted into New Common Stock[(b)]	(254,259)	(32,406)	(10,603)
Issued for General Unsecured Claims	—	—	1,630,447
Outstanding as of December 31, 2021	10,856,852	12,313,273	11,388,371

(a) As of December 31, 2021, we had 2,318,446 of reserved Class C Warrants.

(b) As of December 31, 2021, we issued 188,292 common shares as a result of Warrant exercises.

As discussed in Note 2, on the Effective Date, we issued Class A, Class B and Class C Warrants that are initially exercisable for one share of New Common Stock per Warrant at initial exercise prices of $27.63, $32.13 and $36.18 per share, respectively, subject to adjustments pursuant to the terms of the Warrants. The Warrants are exercisable from the Effective Date until February 9, 2026. The Warrants contain customary anti-dilution adjustments in the event of any stock split, reverse stock split, reclassification, stock dividend or other distributions. The exercise prices of the Warrants were adjusted to prevent the dilution of rights for the effects of the quarterly dividend distribution on December 9, 2021, and the adjusted exercise prices are $27.08, $31.49, and $35.46 per share for the Class A, Class B and Class C Warrants, respectively.

Chapter 11 Proceedings

Upon our emergence from Chapter 11 on February 9, 2021, as discussed in Note 2, Predecessor common stock and preferred stock were canceled and released under the Plan without receiving any recovery on account thereof.

Noncontrolling Interests

In the 2019 Predecessor Period and part of the 2020 Predecessor Period, we owned 23,750,000 common units in the Chesapeake Granite Wash Trust (the "Trust") representing a 51% beneficial interest. We determined that the Trust was a VIE and that we were the primary beneficiary. As a result, the Trust was included in our consolidated financial statements. In the 2020 Predecessor Period, we sold our interests in the Mid-Continent operating area and the units we owned in the Trust. See Note 4 for additional discussion.

13. Share-Based Compensation

As discussed in Note 2, on the Effective Date, our Predecessor common stock was canceled and New Common Stock was issued. Accordingly, our then existing share-based compensation awards were also canceled, which resulted in the recognition of any previously unamortized expense related to the canceled awards on the date of cancellation. Share-based compensation for the Predecessor and Successor Periods is not comparable.

Successor Share-Based Compensation

As of the Effective Date, the Board adopted the 2021 Long Term Incentive Plan (the "LTIP") with a share reserve equal to 6,800,000 shares of New Common Stock. The LTIP provides for the grant of restricted stock units, restricted stock awards, stock options, stock appreciation rights, performance awards and other stock awards to the Company's employees and non-employee directors.

Restricted Stock Units. In the 2021 Successor Period, we granted restricted stock units to employees and non-employee directors under the LTIP, which will vest over a three-year and one-year period, respectively. The fair value of restricted stock units is based on the closing sales price of our common stock on the date of grant, and compensation expense is recognized ratably over the requisite service period. A summary of the changes in unvested restricted stock units is presented below:

	Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share
	(in thousands)	
Unvested as of February 10, 2021	—	$ —
Granted [(a)]	1,202	$ 52.60
Vested [(a)]	(377)	$ 65.66
Forfeited	(50)	$ 44.37
Unvested as of December 31, 2021	775	$ 46.77

(a) Due to the Vine Acquisition, each Vine restricted stock unit was converted into a Company restricted stock unit. As a result, approximately 430 thousand Vine restricted stock units were converted to Company restricted stock units, of which approximately 375 thousand restricted stock units were accelerated. We recognized accelerated share-based compensation expense in other operating expense on our consolidated statement of operations.

The aggregate intrinsic value of restricted stock units that vested during the 2021 Successor Period was approximately $25 million based on the stock price at the time of vesting.

As of December 31, 2021, there was approximately $27 million of total unrecognized compensation expense related to unvested restricted stock units. The expense is expected to be recognized over a weighted average period of approximately 2.28 years.

Performance Share Units. In the 2021 Successor Period, we granted performance share units ("PSUs") to senior management under the LTIP, which will generally vest over a three-year period and will be settled in shares. The performance criteria include share price hurdles, total shareholder return ("TSR"), and relative TSR ("rTSR"). The share price hurdle award could result in a payout between 0% - 100% of the target units, and the TSR and rTSR awards could result in a total payout between 0% - 200% of the target units. The fair value of the PSUs was measured on the grant date using a Monte Carlo simulation, and compensation expense is recognized ratably over the requisite service period because these awards depend on a combination of service and market criteria.

The following table presents the assumptions used in the valuation of the PSUs granted in 2021:

Assumption	Share Price Hurdle	TSR, rTSR
Risk-free interest rate	0.30 %	0.23 %
Volatility	68.4 %	71.4 %

A summary of the changes in unvested PSUs is presented below:

	Unvested Performance Share Units	Weighted Average Grant Date Fair Value Per Share
	(in thousands)	
Unvested as of February 10, 2021	—	$ —
Granted	201	$ 64.41
Vested	(9)	$ 38.95
Forfeited	(9)	$ 55.42
Unvested as of December 31, 2021	183	$ 66.12

The aggregate intrinsic value of PSUs that vested during the 2021 Successor Period was approximately $0.6 million based on the stock price at the time of vesting.

As of December 31, 2021, there was approximately $10 million of total unrecognized compensation expense related to unvested PSUs. The expense is expected to be recognized over a weighted average period of approximately 2.44 years.

Predecessor Share-Based Compensation

Our Predecessor share-based compensation program consisted of restricted stock, stock options, PSUs and cash restricted stock units (“CRSUs”) granted to employees and restricted stock granted to non-employee directors under our long-term incentive plans. The restricted stock and stock options were equity-classified awards and the PSUs and CRSUs were liability-classified awards.

Restricted Stock Units. We granted restricted stock units to employees and non-employee directors. The following table provides information related to restricted stock units activity for the Predecessor periods presented:

	Unvested Restricted Stock Units		Weighted Average Grant Date Fair Value Per Share
	(in thousands)		
Unvested as of January 1, 2021	1	$	616.57
Granted	—	$	—
Vested	—	$	—
Forfeited/canceled	(1)	$	611.47
Unvested as of February 9, 2021	—	$	—
Unvested as of January 1, 2020	52	$	709.85
Granted	68	$	60.00
Vested	(21)	$	791.69
Forfeited	(98)	$	243.13
Unvested as of December 31, 2020	1	$	616.57
Unvested as of January 1, 2019	59	$	886.20
Granted	30	$	530.44
Vested	(30)	$	876.18
Forfeited	(7)	$	744.74
Unvested as of December 31, 2019	52	$	709.85

Stock Options. In the 2020 Predecessor Period, we granted members of management stock options that vested ratably over a three-year period. Each stock option award had an exercise price equal to the closing price of our common stock on the grant date. Outstanding options expired seven years to ten years from the date of grant.

We utilized the Black-Scholes option-pricing model to measure the fair value of stock options. The expected life of an option was determined using the simplified method. Volatility assumptions were estimated based on the average historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate was based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield was based on an annual dividend yield, taking into account our dividend policy, over the expected life of the option.

The following table provides information related to stock option activity for the Predecessor periods presented:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value(a)
	(in thousands)			($ in millions)
Outstanding as of January 1, 2021	20	$ 1,429.11	4.27	$ —
Granted	—	$ —		
Exercised	—	$ —		$ —
Expired	(1)	$ 741.86		
Forfeited/canceled	(19)	$ 1,452.40		
Outstanding as of February 9, 2021	—	$ —	—	$ —
Exercisable as of February 9, 2021	—	$ —	—	$ —
Outstanding as of January 1, 2020	90	$ 1,420.90	5.70	$ —
Granted	—	$ —		
Exercised	—	$ —		$ —
Expired	(23)	$ 914.50		
Forfeited	(47)	$ 1,666.21		
Outstanding as of December 31, 2020	20	$ 1,429.11	4.27	$ —
Exercisable as of December 31, 2020	19	$ 1,439.55	4.35	$ —
Outstanding as of January 1, 2019	90	$ 1,440.18	7.15	$ —
Granted	5	$ 594.00		
Exercised	—	$ —		$ —
Expired	(2)	$ 1,272.94		
Forfeited	(3)	$ 793.40		
Outstanding as of December 31, 2019	90	$ 1,420.90	5.70	$ —
Exercisable as of December 31, 2019	65	$ 1,656.14	4.86	$ —

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

Restricted Stock, Stock Option, and PSU Compensation. We recognized the following compensation costs, net of actual forfeitures, related to restricted stock, stock options, and PSUs for the periods presented:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
General and administrative expense	$ 7	$ 3	$ 20	$ 26
Oil and natural gas properties	2	—	1	2
Oil, natural gas and NGL production expense	2	—	1	3
Exploration expense	—	—	—	1
Total restricted stock, stock option, and PSU compensation	$ 11	$ 3	$ 22	$ 32

14. Employee Benefit Plans

Our qualified 401(k) profit sharing plan ("401(k) Plan") is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. We match employee contributions dollar for dollar (subject to a maximum contribution of 6% of an employee's base salary and performance bonus) in cash. In April 2021, the 401(k) match was changed from 15% to 6%. We contributed $8 million, $2 million, $24 million and $29 million to the 401(k) Plan in 2021 Successor Period, 2021 Predecessor Period, 2020 Predecessor Period and 2019 Predecessor Period, respectively.

15. Derivative and Hedging Activities

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All of our oil and natural gas derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty. None of our open oil and natural gas derivative instruments were designated for hedge accounting as of December 31, 2021 and 2020.

Oil and Natural Gas Derivatives

As of December 31, 2021 and 2020, our oil and natural gas derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and swap options.
- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Collars*: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil and natural gas derivative instrument assets (liabilities) as of December 31, 2021 and 2020 are provided below:

	Successor		Predecessor	
	December 31, 2021		December 31, 2020	
	Notional Volume	Fair Value	Notional Volume	Fair Value
Oil (mmbbl):				
Fixed-price swaps	13	$ (356)	27	$ (136)
Basis protection swaps	9	(2)	7	(1)
Total oil	22	(358)	34	(137)
Natural gas (bcf):				
Fixed-price swaps	637	(675)	728	10
Collars	205	(82)	53	8
Call options	18	(17)	—	—
Basis protection swaps	252	(11)	66	1
Total natural gas	1,112	(785)	847	19
Total estimated fair value		$ (1,143)		$ (118)

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. See further discussion below under *Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)*.

Effect of Derivative Instruments – Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2021 and 2020 on a gross basis and after same-counterparty netting:

	Gross Fair Value	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheets
Successor			
As of December 31, 2021			
Commodity Contracts:			
Short-term derivative asset	$ 56	$ (51)	$ 5
Short-term derivative liability	(950)	51	(899)
Long-term derivative liability	(249)	—	(249)
Total derivatives	$ (1,143)	$ —	$ (1,143)
Predecessor			
As of December 31, 2020			
Commodity Contracts:			
Short-term derivative asset	$ 84	$ (65)	$ 19
Long-term derivative asset	5	(5)	—
Short-term derivative liability	(158)	65	(93)
Long-term derivative liability	(49)	5	(44)
Total derivatives	$ (118)	$ —	$ (118)

As of December 31, 2021 and 2020, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Consolidated Statements of Operations

The components of oil and natural gas derivatives are presented below:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Gains (losses) on undesignated oil and natural gas derivatives	$ (1,127)	$ (379)	$ 629	$ 40
Losses on terminated cash flow hedges	—	(3)	(33)	(35)
Total oil and natural gas derivatives	$ (1,127)	$ (382)	$ 596	$ 5

Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

A reconciliation of the changes in accumulated other comprehensive income (loss) in our consolidated statements of stockholders' equity related to our cash flow hedges is presented below:

	Successor		Predecessor					
	Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2020		Year Ended December 31, 2019	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
Balance, beginning of period	$ —	$ —	$ (12)	$ 45	$ (45)	$ 12	$ (80)	$ (23)
Losses reclassified to income	—	—	3	3	33	33	35	35
Fresh start adjustments	—	—	9	9	—	—	—	—
Elimination of tax effects	—	—	—	(57)	—	—	—	—
Balance, end of period	$ —	$ —	$ —	$ —	$ (12)	$ 45	$ (45)	$ 12

Our accumulated other comprehensive loss represented the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. The remaining deferred gain or loss amounts were to be recognized in earnings in the month for which the original contract months were to occur. In connection with our adoption of fresh start accounting, we recorded a fair value adjustment to eliminate the accumulated other comprehensive income related to hedging settlements including the elimination of tax effects. See Note 3 for a discussion of fresh start accounting adjustments.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are highly rated or deemed by us to have acceptable credit strength and deemed by management to be competent and competitive market-makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2021, our oil and natural gas derivative instruments were spread among ten counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that were also lenders (or affiliates of lenders) under our DIP Credit Facility. The contracts entered into with these counterparties are secured by the same collateral that secures the pre-petition revolving credit facility. The counterparties' obligations must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. As of December 31, 2021, we did not have any cash or letters of credit posted as collateral for our commodity derivatives.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, natural gas and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are compared to the values given by our counterparties for reasonableness. As our oil, natural gas and NGL derivatives do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2021 and 2020:

	Successor	Predecessor
Significant Other Observable Inputs (Level 2)	**December 31, 2021**	**December 31, 2020**
Derivative Assets (Liabilities):		
Commodity assets	$ 56	$ 88
Commodity liabilities	(1,199)	(206)
Total derivatives	$ (1,143)	$ (118)

16. Capitalized Exploratory Well Costs

A summary of the changes in our capitalized exploratory well costs for the periods presented is detailed below. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	**Period from January 1, 2021 through February 9, 2021**	**Year Ended December 31, 2020**	**Year Ended December 31, 2019**
Balance, beginning of period	$ —	$ —	$ 7	$ 36
Additions pending the determination of proved reserves	24	—	—	7
Divestitures and other	—	—	—	(3)
Reclassifications to proved properties	(10)	—	—	(17)
Charges to exploration expense	—	—	(7)	(16)
Balance, end of period	$ 14	$ —	$ —	$ 7

We had no projects with suspended exploratory well costs capitalized for a period greater than one year as of December 31, 2021, 2020 and 2019, respectively.

17. Other Property and Equipment

Other Property and Equipment

A summary of other property and equipment held for use and the estimated useful lives thereof is as follows:

	Successor December 31, 2021	Predecessor December 31, 2020	Estimated Useful Life (in years)
Buildings and improvements	$ 330	$ 1,038	10 – 39
Computer equipment	87	356	5
Land	37	113	
Sand mine	2	81	10 – 30
Natural gas compressors[(a)]	—	36	3 – 20
Other	39	130	5 – 20
Total other property and equipment, at cost	495	1,754	
Less: accumulated depreciation	(26)	(799)	
Total other property and equipment, net	$ 469	$ 955	

(a) Includes assets under finance lease of $27 million, less accumulated depreciation of $18 million as of December 31, 2020. The related amortization expense for assets under finance lease is included in depreciation, depletion and amortization expense on our consolidated statement of operations. The lease contract was renegotiated as part of our bankruptcy process and the changes to the contract resulted in the reclassification of the finance lease as an operating lease in March 2021.

18. Investments

FTS International, Inc. (NYSE: FTSI). In the 2019 Predecessor Period, the hydraulic fracturing industry experienced challenging operating conditions resulting in the fair value of our investment in FTSI falling below book value of $65 million and remaining below that amount as of the end of the year. Based on FTSI's 2019 operating results and FTSI's share price of $1.04 per share as of December 31, 2019, we determined that the reduction in fair value was other-than-temporary, and recognized an impairment of our investment in FTSI of approximately $43 million.

In the 2020 Predecessor Period, FTSI filed for Chapter 11 bankruptcy and we recognized an impairment of our entire investment of $23 million. FTSI emerged from bankruptcy on November 19, 2020, and this restructuring resulted in a reduction of the common stock we owned in FTSI from 20% to less than 2%. The decreased ownership percentage and the loss of significant influence required us to measure the investment at fair value as of December 31, 2020.

In the 2021 Successor Period, FTSI announced it would be acquired in an all cash deal that is expected to close in 2022. As of December 31, 2021, the investment continues to be measured at fair value.

JWH Midstream LLC. In the 2019 Predecessor Period, in connection with the acquisition of WildHorse, we obtained a 50% membership interest in JWH Midstream LLC ("JWH"). The carrying value of our investment in JWH, which was being accounted for as an equity method investment, was approximately $17 million. In the 2019 Predecessor Period, we paid approximately $7 million to terminate our involvement in the partnership. This removed us from any future obligations related to this joint venture and, therefore, we impaired the full value of the investment and recognized approximately $24 million of impairment expense in the 2019 Predecessor Period.

19. Impairments

Impairments of Oil and Natural Gas Properties

A summary of our impairments of oil and natural gas properties for the periods presented is as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Total impairments of oil and natural gas properties	$ —	$ —	$ 8,446	$ 8

During the 2020 Predecessor Period, the decrease in demand for crude oil primarily due to the combined impacts of COVID-19 and the OPEC+ production increases resulted in decreases in then current and then expected long-term crude oil and NGL sale prices. These conditions resulted in reductions to the market capitalization of peer companies in the energy industry. We determined these adverse market conditions represented a triggering event to perform an impairment assessment of our long-lived assets used in, and in support of, our operations, including proved oil and gas properties, and our sand mine assets.

Proved Oil and Gas Properties

Our impairment test involved a Step 1 assessment to determine if the net book value of our proved oil and natural gas properties is expected to be recovered from the estimated undiscounted future cash flows.

- We calculated the expected undiscounted future net cash flows of our long-lived assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip pricing escalated by an inflationary rate (ii) pricing adjustments for differentials, (iii) operating costs, (iv) capital investment plans, (v) future production volumes, and (vi) estimated proved reserves.

- Unprecedented volatility in the price of oil due to the decrease in demand led us to rely on NYMEX strip pricing, which represents a Level 1 input.

Certain oil and gas properties in our Eagle Ford, Powder River Basin, and Mid-Continent and other non-core operating areas failed the Step 1 assessment. For these assets, we used a discounted cash flow analysis to estimate fair value. The expected future net cash flows were discounted using a rate of 11%, which we believe represents the estimated weighted average cost of capital of a theoretical market participant. Based on Step 2 of our long-lived assets impairment test, we recognized an $8.446 billion impairment because the carrying value exceeded estimated fair market value as of March 31, 2020.

- Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate, adjusted for differentials, and (v) a market-based weighted average cost of capital. We utilized NYMEX strip pricing, adjusted for differentials, to value the reserves. The NYMEX strip pricing inputs used are classified as Level 1 fair value assumptions and all other inputs are classified as Level 3 fair value assumptions.

Impairments of Fixed Assets

A summary of our impairments of fixed assets by asset class and other charges for the Successor and Predecessor Periods is as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Sand mine	$ —	$ —	$ 76	$ —
Natural gas compressors	—	—	13	—
Buildings and land	—	—	—	1
Other	1	—	—	2
Total impairments of fixed assets and other	$ 1	$ —	$ 89	$ 3

In the 2020 Predecessor Period, we recorded a $76 million impairment of our sand mine assets that support our Eagle Ford operating area for the difference between the fair value and carrying value of the assets as well as a $13 million impairment of compressor inventory due to a lack of a current market for compressors.

20. Exploration Expense

A summary of our exploration expense for the Successor and Predecessor Periods is as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Impairments of unproved properties	$ 1	$ 2	$ 411	$ 32
Dry hole expense	1	—	7	25
Geological and geophysical expense and other	5	—	9	27
Exploration expense	$ 7	$ 2	$ 427	$ 84

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. The exploration expense charges during the 2020 Predecessor Period are primarily the result of non-cash impairment charges in unproved properties, primarily in our Eagle Ford, Haynesville, Powder River Basin and Mid-Continent operating areas. The decrease in geological and geophysical expense in the 2021 Successor Period, 2021 Predecessor Period and 2020 Predecessor Period was due to fewer exploratory geological and geophysical projects.

21. Other Operating Expense (Income), Net

In the 2021 Successor Period, we recognized approximately $59 million of costs related to our acquisition of Vine, which included consulting fees, financial advisory fees, and legal fees. Additionally, we recognized approximately $36 million of severance expense as a result of the Vine Acquisition, which included $15 million of cash severance and $21 million of non-cash severance, primarily related to the issuance of New Common Stock for the acceleration of certain Vine restricted stock unit awards. A majority of Vine executives and employees were terminated on the date of the acquisition. These executives and employees were entitled to severance benefits in accordance with existing employment agreements.

In the 2020 Predecessor Period, we terminated certain gathering, processing and transportation contracts and recognized a non-recurring $80 million expense related to the contract terminations. The contract terminations removed approximately $169 million of future commitments related to gathering, processing and transportation agreements. Additionally, we recognized $9 million of expense related to the impairment of sand mine inventory and $42 million of other operating expense primarily related to royalty settlements and other legal matters offset by $51 million of income from the amortization of VPP deferred revenue. In the 2020 Predecessor Period, we sold the assets related to our remaining volumetric production payment and extinguished the liability related to the production volume delivery obligation.

In the 2019 Predecessor Period, we recorded approximately $37 million of costs related to our acquisition of WildHorse which consisted of consulting fees, financial advisory fees, legal fees and travel and lodging expenses. In addition, we recorded approximately $38 million of severance expense as a result of the acquisition of WildHorse. A majority of the WildHorse executives and employees were terminated on the date of acquisition. These executives and employees were entitled to severance benefits in accordance with existing employment agreements.

22. Separation and Other Termination Costs

In the 2021 Successor Period and 2021 Predecessor Period, we incurred charges in of approximately $11 million and $22 million, respectively, related to one-time termination benefits for certain employees. In the 2020 Predecessor Period and 2019 Predecessor Period, we incurred charges of approximately $44 million and $12 million, respectively, related to one-time termination benefits for certain employees.

23. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below:

	Successor	Predecessor	
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Asset retirement obligations, beginning of period	$ 241	$ 144	$ 211
Additions[(a)]	48	—	1
Revisions [(b)]	63	—	(14)
Settlements and disposals[(c)]	(3)	(1)	(66)
Accretion expense	11	1	12
Impact of fresh start accounting	—	97	—
Asset retirement obligations, end of period	360	241	144
Less current portion	11	5	5
Asset retirement obligations, long-term	$ 349	$ 236	$ 139

(a) During the 2021 Successor Period, approximately $44 million of additions relate to the acquisition of Vine. See Note 4 for further discussion of these transactions.

(b) Revisions primarily represent changes in the present value of liabilities resulting from changes in estimated costs and economic lives of producing properties.

(c) During the 2020 Predecessor Period, approximately $49 million and $14 million of disposals related to our Mid-Continent and Haynesville assets, respectively. See Note 4 for further discussion of these transactions.

24. Major Customers

For the 2021 Successor Period, sales to Valero Energy Corporation and Energy Transfer Crude Marketing accounted for approximately 14% and 11%, respectively, of total revenues (before the effects of hedging). For the 2021 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% of total revenues (before the effects of hedging). For the 2020 and 2019 Predecessor Periods, sales to Valero Corporation constituted 17% and 12% of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2021 Successor Period or 2021, 2020 or 2019 Predecessor Periods.

25. Subsequent Events

On January 24, 2022, Chesapeake entered into definitive agreements to acquire Chief and associated non-operated interests held by affiliates of Tug Hill, Inc. ("Tug Hill"), for $2.0 billion in cash and approximately 9.44 million common shares. Chief and Tug Hill hold producing assets and an inventory of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania. The cash portion of the transaction will be financed with cash on hand and the use of our Exit Credit Facility. The transaction, which is subject to customary closing conditions, including certain regulatory approvals, is expected to close by the end of the first quarter of 2022. In January 2022, we announced our intent to increase the base quarterly dividend to $0.50 per share beginning in the second quarter of 2022, reflecting the cash flow accretion of the transaction.

Additionally, on January 24, 2022, Chesapeake signed an agreement to sell its Powder River Basin assets in Wyoming to Continental Resources, Inc. (NYSE: CLR) for approximately $450 million in cash. The transaction, which is subject to certain customary closing conditions, is expected to close in the first quarter of 2022. At closing, net proceeds from the sale will go toward the purchase price of the Chief Acquisition. The Powder River Basin assets were not classified as held for sale as of December 31, 2021, as the agreement had not been finalized and formal authorization from Chesapeake’s Board of Directors had not yet been obtained.

Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities (unaudited)

Net Capitalized Costs

Capitalized costs related to our oil, natural gas and NGL producing activities are summarized as follows:

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Oil and oil and natural gas properties:		
Proved	$ 7,682	$ 25,734
Unproved	1,530	1,550
Total	9,212	27,284
Less accumulated depreciation, depletion and amortization	(882)	(23,007)
Net capitalized costs	$ 8,330	$ 4,277

Unproved properties as of December 31, 2021 and 2020, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We will continue to evaluate our unproved properties, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties not held by production to be transferred into the amortization base over the next five years.

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

Costs incurred in oil and natural gas property acquisition, exploration and development, including capitalized interest and asset retirement costs, are summarized as follows:

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Acquisition of Properties[(a)]:				
Proved properties	$ 2,183	$ —	$ 3	$ 3,264
Unproved properties	1,121	—	6	792
Exploratory costs	31	—	8	42
Development costs	717	58	887	2,177
Costs incurred	$ 4,052	$ 58	$ 904	$ 6,275

(a) Includes \$2.181 billion and \$1.118 billion of proved and unproved property acquisitions, respectively, related to our acquisition of Vine in 2021.

Results of Operations from Oil, Natural Gas and NGL Producing Activities

The following table includes revenues and expenses associated directly with our oil, natural gas and NGL producing activities for the periods presented. It does not include any interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and NGL operations.

	Successor	Predecessor		
	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Oil, natural gas and NGL sales	$ 4,401	$ 398	$ 2,745	$ 4,517
Oil and natural gas derivatives and VPP revenue	(1,127)	(382)	652	68
Production expenses	(297)	(32)	(373)	(520)
Gathering, processing and transportation expenses	(780)	(102)	(1,082)	(1,082)
Severance and ad valorem taxes	(158)	(18)	(149)	(224)
Exploration	(7)	(2)	(427)	(84)
Depletion and depreciation	(882)	(64)	(1,014)	(2,177)
Accretion of asset retirement obligations	(11)	(1)	(12)	(11)
Impairment of oil and natural gas properties	—	—	(8,446)	(8)
Imputed income tax provision[(a)]	(269)	48	1,840	(125)
Results of operations from oil, natural gas and NGL producing activities	$ 870	$ (155)	$ (6,266)	$ 354

(a) The imputed income tax provision is hypothetical (at the statutory tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision (benefit) will be payable (receivable).

Oil, Natural Gas and NGL Reserve Quantities

Our petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2021, 2020 and 2019. Independent petroleum engineering firm LaRoche Petroleum Consultants, Ltd. estimated an aggregate of 91% of our estimated proved reserves (by volume) as of December 31, 2021.

Proved oil, natural gas and NGL reserves are those quantities of oil, natural gas and NGL 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules, the price is calculated using 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 the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. A project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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. 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Developed oil, natural gas and NGL reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods where production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

The information provided below on our oil, natural gas and NGL reserves is presented in accordance with regulations prescribed by the SEC. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. These changes could be material and could occur in the near term.

Presented below is a summary of changes in estimated reserves for the periods presented:

	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
December 31, 2021				
Proved reserves, beginning of period (Predecessor)	161.3	3,530	52.0	802
Extensions, discoveries and other additions	41.0	1,744	16.9	348
Revisions of previous estimates	33.3	1,522	21.1	308
Production	(25.9)	(807)	(8.0)	(168)
Sale of reserves-in-place	—	—	—	—
Purchase of reserves-in-place	—	1,835	—	306
Proved reserves, end of period (Successor)	209.7	7,824	82.0	1,596
Proved developed reserves:				
Beginning of period (Predecessor)	158.1	3,196	51.4	742
End of period (Successor)	165.7	4,246	61.7	935
Proved undeveloped reserves:				
Beginning of period (Predecessor)	3.2	334	0.6	60
End of period[(a)] (Successor)	44.0	3,578	20.3	661

	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
December 31, 2020				
Proved reserves, beginning of period (Predecessor)	358.0	6,566	120.0	1,572
Extensions, discoveries and other additions	1.1	100	0.4	18
Revisions of previous estimates	(148.2)	(2,326)	(50.6)	(586)
Production	(37.3)	(684)	(11.3)	(163)
Sale of reserves-in-place	(12.3)	(126)	(6.5)	(39)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period (Predecessor)	161.3	3,530	52.0	802
Proved developed reserves:				
Beginning of period (Predecessor)	201.4	3,377	82.1	846
End of period (Predecessor)	158.1	3,196	51.4	742
Proved undeveloped reserves:				
Beginning of period (Predecessor)	156.6	3,189	37.9	726
End of period[(a)] (Predecessor)	3.2	334	0.6	60
December 31, 2019				
Proved reserves, beginning of period (Predecessor)	215.5	6,777	103.3	1,448
Extensions, discoveries and other additions	52.2	897	13.9	216
Revisions of previous estimates	(40.9)	(516)	(15.8)	(143)
Production	(43.0)	(728)	(12.3)	(177)
Sale of reserves-in-place	(1.8)	(23)	(1.4)	(7)
Purchase of reserves-in-place	176.0	159	32.3	235
Proved reserves, end of period (Predecessor)	358.0	6,566	120.0	1,572
Proved developed reserves:				
Beginning of period (Predecessor)	127.6	3,314	67.9	748
End of period (Predecessor)	201.4	3,377	82.1	846
Proved undeveloped reserves:				
Beginning of period (Predecessor)	87.9	3,463	35.4	700
End of period[(a)] (Predecessor)	156.6	3,189	37.9	726

(a) As of December 31, 2021, 2020 and 2019, there were no PUDs that had remained undeveloped for five years or more.

During 2021, we acquired 306 mmboe primarily related to the acquisition of Vine. We recorded extensions and discoveries of 348 mmboe following our emergence from bankruptcy on February 9, 2021 and certainty regarding our ability to finance the development of our proved reserves over a five-year period. We recorded 308 mmboe of upward revisions of previous estimates, which consisted of 214 mmboe due to lateral length adjustments, performance and updates to our five-year development plan and 94 mmboe due to higher oil, natural gas and NGL prices in 2021. The oil and natural gas prices used in computing our reserves as of December 31, 2021, were $66.56 per bbl and $3.60 per mcf, respectively, before basis differential adjustments.

During 2020, we recorded extensions and discoveries of 18 mmboe primarily in the Marcellus and Haynesville primarily related to successfully drilled new well additions. We sold 39 mmboe of proved reserves for approximately $136 million primarily in the Mid-Continent. We recorded 586 mmboe of downward revisions of previous estimates consisting of 423 mmboe of downward revisions due to updates to our five-year development plan in contemplation of ongoing market conditions and uncertainty regarding our ability to finance the development of our proved reserves over a five-year period, downward revisions of 208 mmboe due to lower oil, natural gas and NGL prices in 2020, and upward revisions of 45 mmboe due to ongoing portfolio evaluation including performance adjustments. The oil and natural gas prices used in computing our reserves as of December 31, 2020, were $39.57 per bbl and $1.98 per mcf, respectively, before basis differential adjustments.

During 2019, we acquired 235 mmboe primarily related to the acquisition of WildHorse. We recorded extensions and discoveries of 216 mmboe, primarily related to undeveloped well additions in the Marcellus and Eagle Ford operating areas. In addition, we recorded downward revisions of 110 mmboe due to lower oil, natural gas and NGL prices in 2019, and downward revisions of 33 mmboe due to ongoing portfolio evaluation including lateral length adjustments, performance and updates to our five-year development plan. The oil and natural gas prices used in computing our reserves as of December 31, 2019, were $55.69 per bbl and $2.58 per mcf, respectively, before basis differential adjustments.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards Codification Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2021, 2020 and 2019 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure:

	Years Ended December 31,		
	2021	2020	2019
Future cash inflows	$ 33,700 [(a)]	$ 8,247 [(b)]	$ 29,857 [(c)]
Future production costs	(6,735)	(2,963)	(6,956)
Future development costs	(3,687)	(563)	(5,757)
Future income tax provisions	(2,254)	(9)	(75)
Future net cash flows	21,024	4,712	17,069
Less effect of a 10% discount factor	(8,737)	(1,626)	(8,069)
Standardized measure of discounted future net cash flows	$ 12,287	$ 3,086	$ 9,000

(a) Calculated using prices of $66.56 per bbl of oil and $3.60 per mcf of natural gas, before basis differential adjustments.

(b) Calculated using prices of $39.57 per bbl of oil and $1.98 per mcf of natural gas, before basis differential adjustments.

(c) Calculated using prices of $55.69 per bbl of oil and $2.58 per mcf of natural gas, before basis differential adjustments.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2021	2020	2019
Standardized measure, beginning of period[(a)]	$ 3,086	$ 9,000	$ 9,495
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(3,414)	(1,140)	(2,691)
Net changes in prices and production costs	6,674	(5,576)	(3,457)
Extensions and discoveries, net of production and development costs	2,834	71	991
Changes in estimated future development costs	(459)	1,933	366
Previously estimated development costs incurred during the period	130	665	775
Revisions of previous quantity estimates	2,034	(1,839)	(793)
Purchase of reserves-in-place	2,807	—	3,435
Sales of reserves-in-place	—	(112)	(57)
Accretion of discount	309	902	953
Net change in income taxes	(1,423)	14	17
Changes in production rates and other	(291)	(832)	(34)
Standardized measure, end of period[(a)]	$ 12,287	$ 3,086	$ 9,000

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excludes gains and losses on derivatives.

Item 9. *Changes In and Disagreements with Accountants on Accounting and Financial Disclosure*

Not applicable.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded as of December 31, 2021 that our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control-Integrated Framework* (2013) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company's internal control over financial reporting was effective as of December 31, 2021.

Management's assessment and conclusion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021 excludes an assessment of the internal control over financial reporting of Vine Energy, which was acquired in a business combination on November 1, 2021. Vine Energy represents approximately 20% of our consolidated total assets as of December 31, 2021 and approximately 7% of our consolidated revenues for the period from February 10, 2021 through December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ DOMENIC J. DELL'OSSO, JR.

Domenic J. Dell'Osso, Jr.
President and Chief Executive Officer

/s/ MOHIT SINGH

Mohit Singh
Executive Vice President and Chief Financial Officer

February 24, 2022

Item 9B. *Other Information*

Not applicable.

Item 9C. *Disclosure Regarding Foreign Jurisdictions that Prevent Inspections*

Not applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The names of executive officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2022 (the "2022 Proxy Statement").

Item 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2022 Proxy Statement.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholders Matters*

The information called for by this Item 12 is incorporated herein by reference to the 2022 Proxy Statement.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information called for by this Item 13 is incorporated herein by reference to the 2022 Proxy Statement.

Item 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2022 Proxy Statement.

PART IV

Item 15. *Exhibit and Financial Statement Schedules*

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.
3. *Exhibits*. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1	Fifth Amended Joint Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates Pursuant to Chapter 11 of the Bankruptcy Code (Exhibit A of the Confirmation Order).	8-K	001-13726	2.1	1/19/2021	
2.2	Agreement and Plan of Merger, dated as of August 10, 2021, by and among Chesapeake Energy Corporation, Hannibal Merger Sub, Inc., Hannibal merger Sub, LLC, Vine Energy Inc. and Vine Energy holdings LLC.	8-K	001-13726	2.1	8/11/21	
3.1	Second Amended and Restated Certificate of Incorporation of Chesapeake Energy Corporation.	8-K	001-13726	3.1	2/9/2021	
3.2	Second Amended and Restated Bylaws of Chesapeake Energy Corporation.	8-K	001-13726	3.2	2/9/2021	
3.3	Certificate of Elimination of Series B Preferred Stock of Chesapeake Energy Corporation.	10-K	001-13726	3.3	3/1/2021	
4.1	Description of Securities.	8-A	001-13726	N/A	2/9/2021	
10.1	Restructuring Support Agreement, dated June 28, 2020.	8-K	001-13726	10.1	6/29/2020	
10.2	Backstop Commitment Agreement, dated June 28, 2020 (Exhibit 4 to the Restructuring Support Agreement).	8-K	001-13726	10.1	6/29/2020	
10.3	Credit Agreement, dated as of February 9, 2021, among Chesapeake Energy Corporation, as borrower, MUFG Union Bank, N.A., as administrative agent, and the lenders and other parties thereto.	8-K	001-13726	10.1	2/9/2021	
10.4	Registration Rights Agreement, dated as of February 9, 2021, by and among Chesapeake Energy Corporation and the other parties signatory thereto.	8-K	001-13726	10.2	2/9/2021	
10.5	Class A Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.3	2/9/2021	

10.6	Class B Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.4	2/9/2021	
10.7	Class C Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.5	2/9/2021	
10.8	Form of Indemnity Agreement.	8-K	001-13726	10.6	2/9/2021	
10.9†	Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.7	2/9/2021	
10.10	Purchase Agreement, dated as of February 2, 2021, by and among Chesapeake Escrow Issuer LLC, and Goldman Sachs & Co. LLC, RBC Capital Markets, LLC, as representatives of the purchasers signatory thereto, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.10	3/1/2021	
10.11	Indenture dated as of February 5, 2021, among Chesapeake Escrow Issuer LLC, as issuer, the guarantors signatory thereto, and Deutsche Bank Trust Company Americas, as Trustee, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.11	3/1/2021	
10.12	Joinder Agreement, dated as of February 9, 2021, by and among Chesapeake Energy Corporation and the Guarantors party thereto, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.12	3/1/2021	
10.13	First Supplemental Indenture, dated as of February 9, 2021, by and among Chesapeake Energy Corporation, the Guarantors signatory thereto, and Deutsche Bank Trust Company Americas, as Trustee, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.13	3/1/2021	
10.14†	Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	4/27/2021	
10.15†	Agreement by and between Robert D. Lawler and Chesapeake Energy Corporation, dated April 27, 2021.	8-K	001-13726	10.1	4/27/2021	
10.16†	Interim CEO Agreement by and between Michael Wichterich and Chesapeake Energy Corporation, dated April 27, 2021.	8-K	001-13726	10.2	4/27/2021	
10.17†	Form of Incentive Agreement between Executive Vice President / Senior Vice President and Chesapeake Energy Corporation.	10-K/A	001-13726	10.14	4/27/2021	
10.18†	Form of Executive/Employee Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.					X
10.19†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.	10-Q	001-13726	10.9	5/13/21	

10.20	Agreement by and between Frank J. Patterson and the Company, dated June 11, 2021.	8-K	001-13726	10.1	6/11/21
10.21†	Agreement by and between James R. Webb and the Company, dated June 11, 2021.	8-K	001-13726	10.2	6/11/21
10.22†	Agreement by and between William M. Buergler and the Company, dated June 11, 2021.	8-K	001-13726	10.3	6/11/21
10.23	First Amendment dated June 11, 2021 to the Credit Agreement, dated as of February 9, 2021, among Chesapeake Energy Corporation, as borrower, MUFG Union Bank, N.A., as administrative agent, and the lenders and other parties thereto.	8-K	001-13726	10.1	6/14/21
10.24†	Form of Performance Share Unit Award (Absolute TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.10	8/10/21
10.25†	Form of Performance Share Unit Award (Relative TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.11	8/10/21
10.26†	Performance Share Unit Award Agreement with Michael A. Wichterich, Interim Chief Executive Officer, dated April 30, 2021.	10-Q	001-13726	10.5	8/10/21
10.27	Registration Rights Agreement, dated as of August 10, 2021, by and among Chesapeake Energy Corporation, Brix Investment LLC, Brix Investment II LLC, Harvest Investment LLC, Harvest Investment II LLC, Vine Investment LLC and Vine Investment II LLC	8-K	001-13726	10.1	8/11/21
10.28	Merger Support Agreement, dater as of August 10, 2021, by and among Chesapeake Energy Corporation, Hannibal merger Sub, Inc., Hannibal Merger Sub, LLC, Vine Energy, Inc. and the stockholders of Vine Energy Inc. listed thereto.	8-K	001-13726	10.2	8/11/21
10.29†	Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.1	10/12/21
10.30†	Form of Participation Agreement pursuant to Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.2	10/12/21
10.31†	Executive Chairman Agreement by and between Michael Wichterich and Chesapeake Energy Corporation, dated October 11, 2021	8-K	001-13726	10.4	10/12/21
10.32†	Second Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	10/12/21
10.33	Second Amendment to Credit Agreement, dated as of October 29, 2021, among Chesapeake Energy Corporation, as borrower, MUFG Bank, Ltd, as administrative agent, MUFG Union Bank, N.A., as collateral agent, and the lenders and other parties party thereto.	10-Q	001-13726	10.18	11/02/21

10.34	Supplemental Indenture, dated as of November 2, 2021, by and among Chesapeake Energy Corporation, the guarantors party thereto and Wilmington Trust, National Association, as Trustee.	8-K	001-13726	4.1	11/02/21	
10.35	Supplemental Indenture, dated as of November 2, 2021, by and among Chesapeake Energy Corporation, the guarantors party thereto and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.2	11/02/21	
10.36	Partnership Interest Purchase Agreement by and among The Jan & Trevor Rees-Jones Revocable Trust, Rees-Jones Family Holdings, LP, Chief E&D Participants, LP, and Chief E&D (GP) LLC (collectively, as Sellers) and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.					X
10.37	Membership Interest Purchase Agreement by and among Radler 2000 Limited Partnership and Tug Hill, Inc., together as Sellers, and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.					X
10.38	Membership Interest Purchase Agreement by and among Radler 2000 Limited Partnership and Tug Hill, Inc., together as Sellers, and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.					X
21	Subsidiaries of Chesapeake Energy Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of PricewaterhouseCoopers LLP.					X
23.3	Consent of LaRoche Petroleum Consultants, Ltd.					X
31.1	Domenic J. Dell'Osso, Jr., President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Mohit Singh, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Domenic J. Dell'Osso, Jr., President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Mohit Singh, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
95.1	Mine Safety Disclosures					X
99.1	Report of LaRoche Petroleum Consultants, Ltd.					X
101 INS	Inline XBRL Instance Document.					X

101 SCH	Inline XBRL Taxonomy Extension Schema Document.	X
101 CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.	X
101 DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	X
101 LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	X
101 PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	X
104	Cover Page Interactive Data file - the Cover Page Interactive Data File does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document	

* Schedules have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

† Management contract or compensatory plan or arrangement.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about Chesapeake Energy Corporation or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about Chesapeake Energy Corporation or its business or operations on the date hereof.

Item 16. *Form 10-K Summary*

Not applicable.

Signatures

Pursuant to the requirements of Section 13 or 15(d) 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.

CHESAPEAKE ENERGY CORPORATION

Date: February 24, 2022

By: /s/ DOMENIC J. DELL’OSSO, JR.
Domenic J. Dell’Osso, Jr.
President and Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Domenic J. Dell'Osso, Jr. his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

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	Capacity	Date
/s/ DOMENIC J. DELL’OSSO, JR. **Domenic J. Dell’Osso, Jr.**	President and Chief Executive Officer (Principal Executive Officer)	February 24, 2022
/s/ MOHIT SINGH **Mohit Singh**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2022
/s/ GREGORY M. LARSON **Gregory M. Larson**	Vice President - Accounting & Controller (Principal Accounting Officer)	February 24, 2022
/s/ MICHAEL WICHTERICH **Michael Wichterich**	Executive Chairman and Chairman of the Board	February 24, 2022
/s/ TIMOTHY S. DUNCAN **Timothy S. Duncan**	Director	February 24, 2022
/s/ BENJAMIN C. DUSTER, IV **Benjamin C. Duster, IV**	Director	February 24, 2022
/s/ SARAH A. EMERSON **Sarah A. Emerson**	Director	February 24, 2022
/s/ MATTHEW M. GALLAGHER **Matthew M. Gallagher**	Director	February 24, 2022
/s/ BRIAN STECK **Brian Steck**	Director	February 24, 2022

BOARD OF DIRECTORS

Michael A. Wichterich
Executive Chairman of the Board,
Chesapeake Energy Corporation
Founder, Chief Executive Officer and Chairman,
Three Rivers Operating Company LLC

Domenic J. ("Nick") Dell'Osso, Jr.
President and Chief Executive Officer,
Chesapeake Energy Corporation

Timothy S. Duncan [1,2,4]
President, Chief Executive Officer and Director,
Talos Energy

Benjamin C. Duster, IV [1,2]
Founder and Chief Executive Officer,
Cormorant IV Corporation, LLC

Sarah A. Emerson [3,4]
President,
Energy Security Analysis, Inc.
Managing Principal,
ESAI Energy, LLC

Matthew M. Gallagher [1,3]
President and Chief Executive Officer,
Greenlake Energy Ventures, LLC
Venture Partner,
NGP Energy Capital Management, LLC

Brian Steck [2,4]
Chairman,
Civitas Resources, Inc.

(1) Audit Committee
(2) Compensation Committee
(3) Nominating, Governance and Social Responsibility Committee
(4) Environmental and Social Governance Committee

MANAGEMENT TEAM

Domenic J. ("Nick") Dell'Osso, Jr.
President, Chief Executive Officer
and Director

Benjamin E. Russ
Executive Vice President –
General Counsel and Corporate Secretary

Mohit Singh
Executive Vice President
and Chief Financial Officer

Joshua J. Viets
Executive Vice President
and Chief Operating Officer

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at www.chk.com. We will promptly deliver free of charge, upon request, a copy of the annual report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the National Association of Securities Dealers Automated Quotations (NASDAQ) under the symbol CHK. As of April 11, 2022, the record date for our 2022 Annual Meeting of Shareholders, there were approximately 98,000 beneficial owners of our common stock.

INDEPENDENT PUBLIC ACCOUNTANTS

PricewaterhouseCoopers LLP
211 North Robinson Avenue, Suite 1400
Oklahoma City, OK 73102
(405) 290-7200

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
EQ Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-0874
(651) 450-4064
(800) 468-9716 (outside the United States)
shareowneronline.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

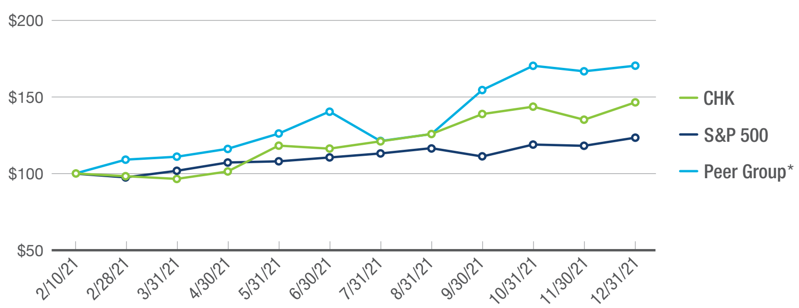
Deutsche Bank Trust
Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
www.db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2021 Annual Report on Form 10-K, which is included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information, except as required by law. We urge you to carefully review and consider the disclosures made in our Form 10-K and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE'S COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on February 10, 2021 and the reinvestment of all dividends. Source: Zacks Investment Research, Inc.



* Apache Corporation, Coterra Energy Inc., Cimarex Energy Co., Devon Energy Corporation, Diamondback Energy Inc., EQT Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Ovintiv Inc., PDC Energy Inc., Range Resources Corporation and Southwestern Energy Company

CHESAPEAKE ENERGY

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118

chk.com