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, 2022

☐ **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

Securities Registered Pursuant to Section 12(g) of the Act: None

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

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

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, 2022, was approximately $3.6 billion. As of February 16, 2023, there were 134,719,821 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2023 Annual Meeting of Stockholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
FORM 10-K
TABLE OF CONTENTS

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. Certain reserves and production information was previously disclosed in a per barrel of oil equivalent, since the majority of our production profile consists of natural gas, we have converted this information, including prior periods, from a per barrel of oil equivalent, to a per one thousand cubic feet of natural gas equivalent, referred to, on such a converted basis, as per Mcfe. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K (this “Form 10-K” or this “report”):

“Adjusted Free Cash Flow” (a non-GAAP measure) means net cash provided by operating activities (GAAP) less cash capital expenditures and contributions to investments, 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.

“Bcfe” means billion cubic feet of natural gas equivalent.

“BLM” means the Bureau of Land Management.

“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.

“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 natural gas, oil 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.

“DD&A” means depreciation, depletion and amortization.

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

“DEI” means diversity, equity and inclusion.

“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 natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

“Effective Date” means February 9, 2021.

“ESG” means environmental, social and governance.

“Exit Credit Facility” means the reserve-based credit facility available upon emergence from bankruptcy. In December 2022, we terminated the Exit Credit Facility.

“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 natural gas or oil 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.

“G&A” means general and administrative expenses.

“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.

“LTIP” means the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.

“LNG” means liquefied natural gas.

“Marcellus Acquisition” means Chesapeake’s acquisition of Chief and associated non-operated interests held by affiliates of Radler and Tug Hill, Inc., which closed on March 9, 2022, with an effective date of January 1, 2022.

“MBbls” means thousand barrels.

“MMBbls” means million barrels.

“Mcf” means thousand cubic feet.

“Mcfe” means one thousand cubic feet of natural gas equivalent, with one barrel of oil or NGL converted to an equivalent volume of natural gas using the ratio of one barrel of oil or NGL to six Mcf of natural gas.

“MMcf” means million cubic feet.

“MMcfe” means million cubic feet of natural gas equivalent.

“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.

“New Credit Facility” means the reserve-based credit facility entered into on December 9, 2022.

“NGL” means natural gas liquids.

“NYMEX” means New York Mercantile Exchange.

“OPEC+” means Organization of the Petroleum Exporting Countries Plus.

“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 natural gas, oil 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 natural gas and oil 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 natural gas, oil 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” has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part proved natural gas and oil reserves are those quantities of natural gas and oil, 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.

“Radler” means Radler 2000 Limited Partnership.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil 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.

“SOFR” means a rate equal to the secured overnight financing rate as administered by the SOFR Administrator, the Federal Reserve Bank of New York (or a successor administrator of the secured overnight financing rate).

“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 natural gas and oil 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.

“Tcf” means trillion cubic feet.

“Tcfe” means trillion cubic feet of natural gas equivalent.

“Tranche A Loans” means the fully revolving loans made under and on the terms set forth under the Exit Credit Facility which were partially funded on the Effective Date. The Tranche A Loans were repaid in full in connection with our entry into the New Credit Facility.

“Tranche B Loans” means term loans made under and on the terms set forth under the Exit Credit Facility which were fully funded on the Effective Date. The Tranche B Loans were repaid in full in connection with our entry into the New Credit Facility.

"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 natural gas and oil regardless of whether the acreage contains proved reserves.

"Unproved Properties" means properties with no proved reserves.

"Vine" means Vine Energy Inc.

"Vine Acquisition" means Chesapeake's acquisition of Vine Energy Inc. which closed on November 1, 2021.

"Volumetric Production Payment (VPP)" means a limited-term overriding royalty interest in natural gas and oil 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.

"/Mcf" means per Mcf.

"/Mcfe" means per Mcfe.

"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.

"2022 Successor Period" means the year ended December 31, 2022.

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 impact of inflation and commodity price volatility resulting from Russia’s invasion of Ukraine, COVID-19 and related supply chain constraints, and the impact of each on our business, financial condition, results of operations and cash flows, the potential effects of the Plan 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 and our ESG initiatives. Forward-looking and other statements in this Form 10-K regarding our environmental, social and other sustainability plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current, and forward-looking environmental, social and sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. 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 inflation and commodity price volatility resulting from Russia’s invasion of Ukraine, COVID-19 and related supply chain constraints along with the effect on our business, financial condition, employees, contractors, vendors and the global demand for natural gas and oil and U.S. and world financial markets;
- our ability to comply with the covenants under the credit agreement for our New Credit Facility and other indebtedness;
- risks related to potential acquisitions or dispositions;
- our ability to realize anticipated cash cost reductions;
- the volatility of natural gas, oil 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;
- a deterioration in general economic, business or industry conditions;
- uncertainties inherent in estimating quantities of natural gas, oil 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 ability to achieve and maintain ESG certifications, goals and commitments;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to fund cash dividends and repurchases of equity securities, to finance reserve replacement costs and/or satisfy our debt obligations;
- write-downs of our natural gas and oil asset carrying values due to low commodity prices;

- charges incurred in response to market conditions;
- limited control over properties we do not operate;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- potential OTC derivatives regulations limiting our ability to hedge against commodity price fluctuations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- pipeline and gathering system capacity constraints and transportation interruptions;
- legislative, regulatory and ESG initiatives 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;
- an interruption in operations at our headquarters due to a catastrophic event;
- federal and state tax proposals affecting our industry;
- competition in the natural gas and oil exploration and production industry;
- negative public perceptions of our industry;
- 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 Form 10-K.

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 natural gas, oil and NGL from underground reservoirs. We own a large portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 8,400 gross natural gas and oil wells.

On August 2, 2022, we announced that our Eagle Ford assets were non-core to our future capital allocation strategy. While continuing to focus our capital on the premium rock, returns and runway of our Marcellus and Haynesville positions, on January 17, 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for $1.425 billion. On February 17, 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Energy for $1.4 billion.

On March 25, 2022, we sold our Powder River Basin assets in Wyoming to Continental Resources, Inc. for approximately $450 million.

On March 9, 2022, we completed our acquisition of Chief, Radler and associated non-operated interests held by affiliates of Tug Hill, Inc. (“Tug Hill”). Chief, Radler and Tug Hill held producing assets and an inventory of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania.

On November 1, 2021, we completed our acquisition of Vine, an energy company focused on the development of natural gas properties in stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana.

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.

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

Our business strategy is to create shareholder value through the responsible development of our significant resource plays, while continuing to be a leading provider of affordable, reliable, low carbon energy to the United States.

Superior Capital Returns. We consistently focus on optimizing the development of our large resource base with a prioritization of generating high cash returns on capital invested. Our drive toward continuous improvement through engineering innovation and planning enhances margins for our shareholders.

Sustainability Leadership. We are committed to protecting our country's natural resources and reducing our environmental footprint. We continue to foster a focus on environmental excellence through a culture of stewardship and sustainability 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.

Premier Balance Sheet. 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. We further de-risk our margins and cash flows with prudent natural gas hedging that aims to reduce the impact of volatility.

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. In January 2023, we entered into an agreement to sell a portion of our Eagle Ford assets. In February 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets.

Well Data

As of December 31, 2022, we held an interest in approximately 8,400 gross productive wells, including 6,700 wells in which we held a working interest and 1,700 wells in which we held an overriding or royalty interest. Of the 6,700 (4,300 net) wells in which we held a working interest, 3,500 (2,100 net) wells were classified as productive natural gas wells and 3,200 (2,200 net) wells were classified as productive oil wells. During 2022, we operated 6,000 gross wells and held a non-operating working interest in 700 gross wells. We also completed 216 gross (151 net) wells as operator and participated in another 22 gross (1 net) wells completed by other operators. We operate approximately 99% 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:

	2022				2021				2020			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	237	100	151	100	137	100	74	100	203	100	126	100
Dry	—	—	—	—	—	—	—	—	—	—	—	—
Total	237	100	151	100	137	100	74	100	203	100	126	100
Exploratory:												
Productive	—	—	—	—	2	100	1	100	—	—	—	—
Dry	1	100	1	100	—	—	—	—	2	100	2	100
Total	1	100	1	100	2	100	1	100	2	100	2	100

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

	2022		2021		2020	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Marcellus	103	59	83	34	79	33
Haynesville	83	61	40	31	21	19
Eagle Ford	52	32	12	7	86	65
Powder River Basin	—	—	4	3	12	9
Mid-Continent	—	—	—	—	5	—
Other	—	—	—	—	2	2
Total	238	152	139	75	205	128

As of December 31, 2022, we had 91 gross (59 net) wells in the process of being drilled or completed.

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

The following tables present information regarding our net production volumes, average sales price received for our production, and production and gathering, processing and transportation expenses per Mcfe for the periods indicated for our significant fields:

	Production			
	Natural Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Total (Bcfe)
2022				
Marcellus	670	—	—	670
Haynesville	588	—	—	588
Eagle Ford	46	18.7	5.8	193
Total Production	1,308	19.4	6.0	1,461
2021				
Marcellus	471	—	—	471
Haynesville	265	—	—	265
Eagle Ford	51	22.5	6.7	227
Total Production	807	25.9	8.0	1,010
2020				
Marcellus	385	—	—	385
Haynesville	198	—	—	198
Eagle Ford	68	31.3	8.9	309
Total Production	684	37.3	11.3	976

	Average Sales Price of Production[(a)]				Expenses ($/Mcfe)	
	Natural Gas ($/Mcf)	Oil ($/Bbl)	NGL ($/Bbl)	Total ($/Mcfe)	Production	GP&T
2022						
Marcellus	$ 6.03	$ —	$ —	$ 6.03	$ 0.11	$ 0.57
Haynesville	$ 5.92	$ —	$ —	$ 5.92	$ 0.26	$ 0.53
Eagle Ford	$ 5.64	$ 96.10	$ 36.76	$ 11.76	$ 1.22	$ 1.78
Total	$ 5.96	$ 96.07	$ 37.48	$ 6.77	$ 0.33	$ 0.73
2021						
Marcellus	$ 3.16	$ —	$ —	$ 3.16	$ 0.08	$ 0.68
Haynesville	$ 3.96	$ —	$ —	$ 3.96	$ 0.24	$ 0.49
Eagle Ford	$ 3.84	$ 67.14	$ 29.14	$ 8.40	$ 0.85	$ 1.48
Total	$ 3.49	$ 67.01	$ 30.77	$ 4.75	$ 0.33	$ 0.87
2020						
Marcellus	$ 1.64	$ —	$ —	$ 1.64	$ 0.08	$ 0.76
Haynesville	$ 1.83	$ —	$ —	$ 1.83	$ 0.21	$ 0.95
Eagle Ford	$ 1.90	$ 38.38	$ 10.93	$ 4.62	$ 0.65	$ 1.54
Total	$ 1.73	$ 38.16	$ 11.55	$ 2.81	$ 0.38	$ 1.11

(a) Excludes the effect of hedging.

Natural Gas, Oil and NGL Reserves

The tables below set forth information as of December 31, 2022, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value of estimated future net revenue and the standardized measure of discounted future net cash flows. None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated natural gas, oil and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2022			
	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
Proved developed	7,385	157.2	58.9	8,681
Proved undeveloped	3,984	41.2	15.0	4,321
Total proved[(a)]	11,369	198.4	73.9	13,002

	Proved Developed	Proved Undeveloped	Total Proved
Standardized measure[(b)]			$ 26,305
Estimated future net revenue[(b)]	$ 42,773	$ 18,333	$ 61,106
Present value of estimated future net revenue (PV-10)[(b)]	$ 22,356	$ 10,344	$ 32,700

(a) Marcellus, Haynesville and Eagle Ford accounted for approximately 51%, 31%, and 18%, respectively, of our estimated proved reserves by volume as of December 31, 2022.

(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, 2022, 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, 2022. The prices used in our PV-10 measure were $6.36 per mcf of natural gas, $93.67 per bbl of oil and $43.58 per bbl of NGL, 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, 2022. 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 $6.4 billion as of December 31, 2022.

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 natural gas and oil reserves.

As of December 31, 2022, our proved reserve estimates included 4,321 Bcfe of reserves classified as proved undeveloped, compared to 3,963 Bcfe as of December 31, 2021. Presented below is a summary of changes in our proved undeveloped reserves for 2022:

	Total (bcfe)
Proved undeveloped reserves, beginning of period	3,963
Extensions and discoveries	51
Revisions of previous estimates	866
Conversion to proved developed reserves	(1,099)
Purchase of reserves-in-place	552
Sales of reserves-in-place	(12)
Proved undeveloped reserves, end of period	4,321

As of December 31, 2022, all PUDs were planned to be developed within five years of original recording. In 2022, we invested approximately $851 million to convert 1,099 bcfe of PUDs to proved developed reserves. We added 51 bcfe of PUD reserves through extensions and discoveries primarily due to new PUDs added to emerging plays. Revisions of previous estimates resulted in a net upward revision of 866 bcfe. The net upward revision primarily resulted from development plan optimization through prioritizing longer laterals and multi-well pad development in Haynesville for 834 bcfe, 146 bcfe of upward revisions to existing PUD forecasts in Marcellus and Haynesville, partially offset by a downward revision of 114 bcfe due to development plan changes in Marcellus and Eagle Ford. We added 552 bcfe of PUDs through purchase of reserves-in-place related to the Marcellus Acquisition.

The future net revenue attributable to our estimated PUDs was $18.333 billion and the present value was $10.344 billion as of December 31, 2022. These values were calculated assuming that we will expend approximately $4.3 billion to develop these reserves ($1,411 million in 2023, $1,430 million in 2024, $1,184 million in 2025, $165 million in 2026 and $56 million in 2027). 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 commodity prices, unexpected developmental drilling results, title issues and infrastructure availability or constraints.

Of our 13,002 bcfe of proved reserves as of December 31, 2022, approximately 190 bcfe, 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, 2022, 2021 and 2020, 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 Natural Gas, Oil 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 natural gas and oil 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 natural gas, oil 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 Natural Gas,* *Oil and NGL Producing Activities* included in Item 8 of Part II of this report for further discussion of our reserve quantities.

Reserves Estimation

We engaged Netherland, Sewell & Associates, Inc., a third-party engineering firm, to prepare approximately 92% by volume, and approximately 95% by value, of our estimated proved reserves as of December 31, 2022. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical persons at the firm primarily responsible for overseeing the preparation of our reserve estimates are set forth below.

- Over 39 combined years of practical experience in the estimation and evaluation of reserves;
- Licensed Professional Engineer in the State of Texas and Bachelor of Science degree in Chemical Engineering;
- Licensed Professional Geoscientist in the State of Texas and Bachelor of Science and Master of Science degrees in Geology.

Our Corporate Reserves Department prepared approximately 8% by volume, and approximately 5% by value, of our estimated proved reserves as of December 31, 2022, disclosed in this report. Those estimates were established utilizing standard geological and engineering technologies, which are generally accepted by the petroleum industry and were based upon the best available production, engineering and geologic data. These technologies, including computational methods, provide reasonable certainty in our reserves estimation and include technologies and inputs such as drilling results and well performance, decline curve analysis of wells in analogous reservoirs, material balance, volumetric calculation, statistical analysis, well logs, geologic maps and seismic data.

Our Manager – SEC Reserves Engineering, who is in charge of our Corporate Reserves Department, 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. His qualifications include the following:

- Over 15 years of practical experience in the oil and gas industry, with over 13 years in reservoir engineering;
- Licensed Professional Engineer (Petroleum) in the State of Oklahoma;
- Member in good standing of the Society of Petroleum Evaluation Engineers;
- Bachelor of Science in Mechanical Engineering; and
- Master's of Business Administration.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserve estimates. 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 the Manager – SEC Reserves Engineering.
- The Corporate Reserves Department reviews our proved reserves at the close of each quarter.
- Each quarter, Reservoir Managers, the Manager – SEC Reserves Engineering, the Senior Resource Manager, 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 Manager – SEC Reserves Engineering, the Senior Resource Manager, and the Vice President of Corporate and Strategic Planning.

Acreage

The following table sets forth our gross and net developed and undeveloped natural gas and oil leasehold and fee mineral acreage as of December 31, 2022. 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.

	Developed Leasehold		Undeveloped Leasehold		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)					
Marcellus	566	330	167	135	733	465
Haynesville	359	322	111	56	470	378
Eagle Ford	681	480	213	117	894	597
Other[(a)]	316	293	1,348	1,275	1,664	1,568
Total	1,922	1,425	1,839	1,583	3,761	3,008

(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. We do not anticipate any material lease expirations within the next three years.

Marketing

The principal function of our marketing operations is to provide natural gas, oil 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 natural gas and oil 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 natural gas and NGL production are sold to purchasers under percentage-of-index contracts, spot price contracts or percentage-of-proceeds contracts. Under our percentage-of-index contracts, the price we receive is tied to published indices. Under the terms of our percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Oil production is sold under short-to-long term market-sensitive and spot price contracts.

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.

As of December 31, 2022, we had delivery commitments for a total of approximately 3,400 bcf over the next 10 years. These delivery commitments vary each year, and we expect to primarily fulfill these commitments with production from our proved developed reserves.

Major Customers

For the 2022 Successor Period, sales to Shell Energy North America and Valero Energy Corporation accounted for approximately 13% and 10%, respectively, of total revenues (before the effects of hedging). 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 and 2020 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% and 17%, respectively, of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2022 Successor Period, 2021 Successor Period, 2021 Predecessor Period or 2020 Predecessor Period.

Competition

We compete with both major integrated and other independent natural gas and oil 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 natural gas and oil 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 natural gas and oil 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. Shortly thereafter, in November 2021, the Environmental Protection Agency (the “EPA”) proposed new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. The supplemental proposed rule would impose more stringent requirements on the natural gas and oil industry. 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. Although the national commitments in the Paris Agreement create no binding requirements on individual companies or facilities, they do provide indications of the current administration’s policy direction and the types of legislative and regulatory requirements—such as the EPA’s proposed methane rules—that may be needed to achieve those commitments. 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. Shortly thereafter, in August 2022, President Biden signed the Inflation Reduction Act of 2022 (the “IRA”) into law, which, among other things, includes a methane emissions reduction program that amends the Clean Air Act to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a “waste emissions charge” on certain natural gas and oil sources that are already required to report under EPA’s Greenhouse Gas Reporting Program. Such or similar legislation, regulations and initiatives could affect our business and our results of operation by increasing operating and compliance costs.

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 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. For example, in addition to regulations from the EPA and similar agencies, the SEC has issued proposed rules that would mandate extensive disclosure of climate-related risks and other information. For more information, see Item *1A. Risk Factors - "We are subject to extensive governmental regulation, which can change and could adversely impact our business."* The SEC has also indicated plans to propose various other disclosure regulations, including regarding human capital and other ESG matters. 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 gas and oil wells, and the unitization or pooling of gas and oil 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 gas and oil 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 gas and oil 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 natural gas, oil and NGL that we are ultimately able to produce from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered the U.S. 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 increased its review in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, gas and oil measurement and royalty payment obligations for production from federal lands. On January 27, 2021, President Biden issued an executive order indefinitely suspending new natural gas and oil leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal gas and oil permitting and leasing practices. The federal district court in Louisiana issued a permanent injunction against the executive order on August 18, 2022, limited to the thirteen plaintiff states, Louisiana, Alabama, Alaska, Arkansas, Georgia, Mississippi, Missouri, Montana, Nebraska, Oklahoma, Texas, Utah, and West Virginia. In response to the January 27, 2021 executive order, the U.S. Department of the Interior released its "Report On The Federal Oil And Gas Leasing Program" in November 2021, which assessed the current state of gas and oil leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase gas and oil leases. On November 30, 2022, the BLM issued a proposed rule to reduce the release of methane from venting, flaring, and leaks during gas and oil production activities on Federal and Indian leases, exemplifying the Biden Administration's increased focus on the climate change impacts of federal projects, which could result in further changes to the federal gas and oil 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 - Natural gas and oil 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 natural gas and oil 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 natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time that may result in litigation.

Operating Hazards and Insurance

The natural gas and oil 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 $300 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

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

Domenic J. ("Nick") Dell'Osso, Jr., 46, 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, 46, was appointed Executive Vice President and Chief Financial Officer in December 2021. Prior to joining Chesapeake, Mr. Singh served for six years 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.

Joshua J. Viets, ***Executive Vice President and Chief Operating Officer***

Joshua J. Viets, 44, was appointed Executive Vice President and Chief Operating Officer in February 2022. Prior to joining Chesapeake, Mr. Viets worked for 20 years 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, 48, 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, collaboration and calculated risk-taking help us achieve sustainable operational success. We had approximately 1,200 employees as of December 31, 2022. None of our employees were covered by collective bargaining agreements, and our management works to maintain good relations with our employees.

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 Diversity, Equity and Inclusion

We are committed to inclusion and diversity. Building a diverse workforce and equitable and inclusive work culture is an important factor in contributing to Chesapeake’s sustainable success. 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 enacted listing rule). Chesapeake cultivates a workplace in which diverse perspectives are welcomed and respected and where employees feel encouraged to discuss diversity and inclusion.

In 2022, we further advanced our DEI program by nominating an executive sponsor from the Company’s senior management team, along with our inaugural advisory board and council teams. Each of these branches of our DEI program take part in determining strategic priorities, advancing our culture and supporting internal activities that invite all employees to participate in achieving our DEI vision.

Stay Accident Free Everyday (S.A.F.E.)

Safety is more than a company metric, it is core to our commitment to leading a responsible energy future. We set and deliver robust safety standards, prioritizing the well-being of our employees and contractors. 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 and contractors 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 and contractors 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 and discretionary contributions, flexible work hours, generous paid time off and 12 company-paid holidays, 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.

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, as well as potentially reducing our ability to execute routine or strategic business partnerships. 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, state 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 natural gas and oil production activities, which could materially adversely affect our industry and our financial condition and results of operations.

Certain financial institutions, funds and other sources of capital have also elected to restrict or eliminate their investment in certain fossil fuel-related activities. For example, many large financial institutions have announced commitments to reduce the emissions associated with their financing activities, such as through the Glasgow Financial Alliance for Net Zero (“GFANZ”), whose members represent over $130 trillion in capital subject to a goal of net zero financed emissions by 2050. 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 stock or providing financing. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, regardless of whether such efforts are successful, 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. For more information, see our risk factor *“Increasing attention to ESG matters and our ability to achieve and maintain ESG certifications, goals and commitments may impact our business, financial results or stock price.”*

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 expenses and costs will be accurate;
- there will not be delays in closing, lower than expected sales proceeds for the disposed assets or business, residual liabilities, or post-closing claims for indemnification;
- any investment, acquisition, or disposition will not divert management resources from the operation of our business; and
- any investment, acquisition, or disposition 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.

The gas and oil 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 natural gas, oil 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.

Natural gas, oil 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 natural gas, oil and NGL we sell. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low natural gas, oil 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 natural gas and oil prices may result in a reduction of the carrying value of our natural gas and oil properties due to recognizing impairments in proved and unproved properties.

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

- domestic and worldwide supplies of natural gas, oil and NGL, including U.S. inventories of natural gas and oil 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 natural gas, oil, 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 natural gas and oil producing regions, including in connection with the ongoing conflict between Russia and Ukraine;
- 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 natural gas, oil 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, including supply chain constraints, 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, including supply chain constraints, commencing in 2020, and threatens to continue to do so in 2023. 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. 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.

Natural gas and oil prices are expected to continue to be volatile as a result of the ongoing COVID-19 pandemic and other geopolitical factors, and as changes in natural gas and oil 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 natural gas and oil markets will have on our business, financial condition and results of operations.

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

We have been required to write down the carrying value of certain of our natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 *Impairments* within Critical Accounting Estimates 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 natural gas, oil and NGL, our success in developing and producing new reserves and the other risk factors discussed herein. Our forecasted 2023 capital expenditures, inclusive of capitalized interest, are $1.765 - $1.835 billion compared to our 2022 capital spending level of $1.9 billion. Management continues to review operational plans for 2023 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of natural gas, oil 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 natural gas, oil 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 natural gas and oil 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 natural gas and oil reserves and production, and therefore our cash flows 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 natural gas, oil and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas, oil 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, natural gas, oil and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, oil 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 natural gas and oil prices and other factors, many of which are beyond our control.

As of December 31, 2022, approximately 33% 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 $4.3 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 natural gas and oil 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, 2022 present value is based on prices of $6.36 per mcf of natural gas, $93.67 per bbl of oil and $43.58 per bbl of NGL, before 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 natural gas and oil properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for natural gas and oil, 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 gas and oil 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 natural gas and oil 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 gas and oil 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 natural gas, oil and NGL, costs associated with producing natural gas, oil 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 natural gas or oil 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 natural gas and oil 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, natural gas and oil 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 natural gas, oil and NGL price derivative contracts. Our natural gas, oil and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our natural gas, oil 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 natural gas, oil 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 New 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 natural gas and oil prices.

Natural gas, oil 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.

Natural gas and oil 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 gas or oil reservoirs. Drilling for natural gas, oil 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 gas and oil 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 gas and oil 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 natural gas, oil 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 natural gas and oil.

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 natural gas, oil 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 natural gas, oil 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 natural gas, oil 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 gas and oil 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 key systems and 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 natural gas, oil 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 from nation-state sponsored foreign actors and other attackers. 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 or our third-party providers' systems or technologies. 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, or the perception thereof, 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, prevent, or contain 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, the COVID-19 pandemic has increased our exposure to potential cybersecurity breaches as a result of global remote working dynamics for our customers, employees and third-party providers that present additional risk that threat actors may seek to engage in social engineering (for example, phishing) and to exploit vulnerabilities in corporate and non-corporate networks. 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, we are subject to various state privacy laws, such as the California Consumer Privacy Act ("CCPA"), which came into effect in January, 2020, and the California Privacy Rights Act ("CPRA"), which expands upon the CCPA and came into effect in January 2023 (with a lookback period until January 2022). The CCPA and the CPRA, among other things, contain new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provide for statutory fines and penalties for certain data security breaches or other CCPA and CPRA violations. At least fifteen other states have considered, and some have already enacted, privacy laws like the CCPA and the CPRA.

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, droughts, heat waves, winter storms, and ambient temperature or precipitation changes, 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 (including those of our customers or suppliers) 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 or how such frequency or severity may change. Any such events could have a material adverse effect on our results of operations or financial condition. Moreover, any changes in ambient temperatures may impact demand for natural gas if it results in lower energy needs for, among other things, temperature control. While concerns over energy security have, in some situations, seen increased demand for natural gas, sustained concerns over energy security may result in an accelerated adoption of renewable energy and other alternative energy generation or storage, or energy efficiency, technologies. Any such accelerated adoption of alternative energy sources or energy efficiency improvements may decrease demand for our products or otherwise adversely impact our business or results of operations.

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.

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, including petroleum products. 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. The global market is also currently experiencing inflationary pressure, including rising fuel costs, a tightening steel market and labor and supply chain shortages, which could result in increases to our operating and capital costs that are not fixed.

Military and other armed conflicts, including terrorist activities, and related price volatility and geopolitical instability 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, including petroleum products, 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.

For example, in late February 2022, Russia launched a military invasion against Ukraine. Sustained conflict and disruption in the region is likely in the near term, and the longer-term duration of the war is uncertain. The Russian invasion has caused, and could intensify, volatility in natural gas, oil and NGL prices, driving a sharp upward spike in the short term, and may have an impact on global growth prospects, which could in turn affect demand for natural gas and oil. Any such volatility, impacts on demand and disruptions may also magnify the impact of other risk factors described in this report.

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 gas and oil 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 gas and oil, or further reductions in the prices of gas and oil, 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.

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 incorrect in material respects. Actual results may vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

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 gas, oil 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 27, 2021, President Biden issued an executive order indefinitely suspending new natural gas and oil leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal gas and oil permitting and leasing practices. The federal district court in Louisiana issued a permanent injunction against the executive order on August 18, 2022, limited to the thirteen plaintiff states, Louisiana, Alabama, Alaska, Arkansas, Georgia, Mississippi, Missouri, Montana, Nebraska, Oklahoma, Texas, Utah, and West Virginia. In response to the January 27, 2021 executive order, the U.S. Department of the Interior released its “Report On The Federal Oil And Gas Leasing Program” in November 2021, which assessed the current state of gas and oil leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase gas and oil leases. Although we do not expect this ruling to impact the availability of onshore federal gas and oil lease sales, the Biden Administration’s increased 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. At both the federal and state level, for example, there are an increasing number of legislative initiatives and proposals that may lead to reduced demand for fossil fuels such as oil and gas. These include certain tax advantages and other subsidies to support alternative energy sources or that mandate the use of specific fuels or technologies, in addition to the promotion of research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The IRA, signed by President Biden in August 2022, provides significant funding and incentives for research, development and implementation of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change. The IRA also includes a methane emissions reduction program that amends the Clean Air Act to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a “waste emissions charge” on certain natural gas and oil sources that are already required to report under EPA’s Greenhouse Gas Reporting Program. 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. In November 2021, PHMSA issued a final rule that expands certain federal pipeline safety requirements to all onshore gas gathering pipelines, regardless of size or location. The final rule establishes two new types of onshore gas gathering pipelines subject to varying degrees of regulation: all onshore gathering line operators are now subject to PHMSA's annual reporting and incident reporting requirements, and certain previously unregulated rural gas gathering lines must now comply with PHMSA damage prevention and, depending on the size of the pipeline, construction and operational requirements. The final rule became effective on May 16, 2022. 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. State and federal regulatory agencies have also recently focused on a possible connection between the operation of injection wells used for natural gas and oil waste disposal and seismic activity. 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 gas and oil 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 gas and oil sector, including the exploration and production, transmission, processing, and storage segments. The EPA issued a supplemental proposed rule on November 15, 2022 to update, strengthen and expand its November 2021 proposed rule. The supplemental proposed rule would impose more stringent requirements on the natural gas and oil industry. The rule is expected to be finalized in 2023. Additionally, on November 30, 2022, the BLM issued a proposed rule to reduce the methane waste from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. Once finalized, these regulations are likely to 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 gas and oil industry remain a significant possibility. In addition, several states in which we operate have imposed limitations designed to reduce methane emissions from gas and oil 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 gas and oil, thereby adversely impacting our earnings, cash flows and financial position. In addition, federal or state carbon taxes or fees could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, the SEC has issued proposed rules that would mandate extensive disclosure of climate-related risks and other information, including risk management, GHG emissions, financial impacts, and related governance and strategy. In addition to potential costs, these disclosures may be used by some activists for potential litigation or to pressure capital providers to restrict or eliminate investments or other funding. For more information see our risk factor titled *"Negative public perception regarding us or our industry could have an adverse effect on our operations."*

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 gas and oil, 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 gas and oil 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 ESG matters and our ability to achieve and maintain ESG certifications, goals and commitments 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. Expectations regarding voluntary ESG initiatives and disclosures and consumer demand for more sustainable products, including alternative forms of energy, may result in increased costs (including but not limited to increased costs related to compliance, stakeholder engagement, contracting and insurance), changes in demand for certain products, increased availability of (and competition from) alternative energy sources and technologies, increased development of and demand for products that do not use fossil fuels or their derivatives, enhanced compliance or disclosure obligations, or other adverse impacts to our business, financial condition, or results of operations. Additionally, 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 natural gas, oil and NGL in addition to potentially impacting our access to, and costs of, capital.

While we may at times engage in voluntary initiatives (such as voluntary disclosures, certifications, or targets, among others) or commitments to improve our ESG profile and/or products or to respond to stakeholder expectations, such initiatives or achievement of such commitments may be costly and may not have the desired effect. For example, expectations around management of ESG matters continues to evolve rapidly, in many instances due to factors that are out of our control. In addition, we may commit to certain initiatives or goals, and we may not ultimately be able to achieve such commitments or goals, either on the timeframes or costs initially anticipated or at all, due to factors that are within or outside of our control. Moreover, actions or statements that we may take based on expectations, assumptions, or third-party information that we currently believe to be reasonable may subsequently be determined to be erroneous or be subject to misinterpretation. Even if this is not the case, our current actions may subsequently be determined to be insufficient by various stakeholders, and we may be subject to investor or regulator engagement on our ESG initiatives and disclosures, even if such initiatives are currently voluntary. Any 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. For example, plaintiffs have brought litigation against various companies, including those in the fossil fuel sector, alleging that such companies created public nuisances by producing, handling or marketing fuels that contributed to climate change or that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts. While we are not currently parties to any such litigation, the ultimate outcomes of such litigation and its impact to us are uncertain; we could incur substantial legal costs associated with defending against these or similar lawsuits in future.

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. To the extent ESG matters negatively affect our reputation, it may also harm our ability to attract or retain employees or customers.

We expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters, which will likely lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor. Such ESG matters may also impact our suppliers or customers, which could augment existing, or cause additional, impacts to our business or operations.

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 natural gas and oil by increasing our tax burden. The IRA was enacted on August 16, 2022, and includes, among other things, a 15% corporate minimum tax on adjusted financial statement income and a 1% excise tax on stock buybacks. Although we do not believe we will be subject to the corporate minimum tax in 2023, we may become subject to it in future years. Additionally, 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 an increase to the corporate tax rate, an increase to the excise tax on stock buybacks 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.

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

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 natural gas and oil 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.

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. Additionally, more information on our New Common Stock and Warrants can be found in Note 12 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, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. The declaration and payment of any future dividend is subject to the approval of our Board of Directors in its discretion. Since the initial base dividend declared during the second quarter of 2021, we have incrementally increased the base dividend per share. For additional information on our dividends, see Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

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

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. In June 2022, our Board of Directors authorized an increase in the size of the share repurchase program from $1.0 billion to $2.0 billion in aggregate value of our common stock and/or warrants. 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. The share repurchase program expires on December 31, 2023. The following table provides information regarding purchases of our common stock made by us during the quarter ended December 31, 2022. In 2023, our share repurchase program will be subject to a 1% excise tax imposed under the Inflation Reduction Act of 2022.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions)
October 1 - October 31	4,033,368	$ 98.90	4,033,368	$ 934
November 1 - November 30	72,083	$ 99.09	72,083	$ 927
December 1 - December 31	—	$ —	—	$ 927
Total	4,105,451	$ 98.90	4,105,451	

Stockholders

As of February 16, 2023, there were approximately 154 holders of record of our common stock.

Item 6. *Reserved*

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

This Management's Discussion and Analysis of Financial Condition and Results of Operations is intended to provide a reader of our financial statements with management's perspective on our financial condition, liquidity, results of operations and certain other factors that may affect our future results. 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 natural gas, oil and NGL from underground reservoirs. We own a large portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 8,400 natural gas and oil wells as of December 31, 2022. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania ("Marcellus") and the Haynesville/Bossier Shales in northwestern Louisiana ("Haynesville"). Our liquids-rich resource play is in the Eagle Ford Shale in South Texas ("Eagle Ford"). In August 2022, we announced that we viewed the assets in Eagle Ford as non-core to our future capital allocation strategy, and in January 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for $1.425 billion. Additionally, in February 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Energy for $1.4 billion.

Our strategy is to create shareholder value through the responsible development of our significant resource plays while continuing to be a leading provider of affordable, reliable, low carbon energy to the United States. We continue to focus on improving margins through operating efficiencies and financial discipline and improving our 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 natural gas and oil producing activities. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation and general and administrative), through operational efficiencies and 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 answering the call for affordable, reliable, low carbon energy begins with our goal to achieve net zero greenhouse gas emissions (Scope 1 and 2) by 2035. To meet this challenge, we have set meaningful goals including:

- Eliminate routine flaring from all new wells completed from 2021 forward, and enterprise-wide by 2025;
- Reduce our methane intensity to 0.02% by 2025 (achieved approximately 0.05% in 2022); and
- Reduce our GHG intensity to 3.0 metric tons CO2 equivalent per thousand barrel of oil equivalent by 2025 (achieved approximately 3.9 in 2022).

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. As of December 31, 2022, we have received certification for all our operated gas assets in Haynesville and Marcellus as responsibly sourced gas. The MiQ certification provides a verified approach to tracking our commitment to reduce our methane intensity, as well as support our overall objective of achieving net-zero Scope 1 and 2 greenhouse gas emissions by 2035.

Our results of operations as reported in our consolidated financial statements for the 2022 Successor Period, 2021 Successor Period, 2021 Predecessor Period and 2020 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

Acquisitions

On March 9, 2022, we completed our Marcellus Acquisition pursuant to definitive agreements with Chief, Radler and Tug Hill, Inc. dated January 24, 2022. On November 1, 2021, we completed our Vine Acquisition pursuant to a definitive agreement with Vine dated August 10, 2021. These transactions strengthen Chesapeake’s competitive position, meaningfully increasing our operating cash flows and adding high quality producing assets and a deep inventory of premium drilling locations, while preserving the strength of our balance sheet.

Divestitures

On March 25, 2022, we completed the sale of our Powder River Basin assets in Wyoming to Continental Resources, Inc. for $450 million in cash, subject to post-closing adjustments, which resulted in the recognition of a gain of approximately $293 million.

On January 17, 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for $1.425 billion. This transaction, which is subject to certain customary closing conditions, including certain regulatory approvals, is expected to close in the first quarter of 2023. As of December 31, 2022, the assets and liabilities associated with this transaction were classified as held for sale.

On February 17, 2023 we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Energy for $1.4 billion. This transaction, which is subject to certain customary closing conditions, including certain regulatory approvals, is expected to close in the second quarter of 2023.

Investments - Momentum Sustainable Ventures LLC

During the fourth quarter of 2022, we entered into an agreement with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture and sequestration project, which will gather natural gas produced in the Haynesville Shale for re-delivery to Gulf Coast markets, including LNG export. The pipeline is expected to have an initial capacity of 1.7 Bcf/d expandable to 2.2 Bcf/d. The carbon capture portion of the project anticipates capturing and permanently sequestering up to 2.0 million tons per annum of CO2. The natural gas gathering pipeline in-service is projected for the fourth quarter of 2024, and the carbon sequestration portion of the project is subject to regulatory approvals. As of December 31, 2022, we have made capital contributions of $18 million to the project.

New Credit Facility

On December 9, 2022, we entered into a new senior secured reserve-based revolving credit agreement providing for the New Credit Facility, which features an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. The New Credit Facility includes terms that change favorably upon us receiving and maintaining investment grade ratings by S&P, Moody’s and/or Fitch and the satisfaction of certain other conditions. The New Credit Facility matures in December 2027.

Repurchases of Equity Securities and Dividends

In June 2022, our Board of Directors authorized an increase in the size of our share repurchase program from $1.0 billion to up to $2.0 billion in aggregate value of our common stock and/or warrants. During 2022, we repurchased approximately 11.7 million shares of our common stock pursuant to the share repurchase program and had $927 million available under the share repurchase program as of December 31, 2022. In addition, we have paid dividends of approximately $1.2 billion, in aggregate, on our common stock during 2022. In August 2022, we increased our quarterly base dividend by 10% to $0.55 per share beginning with the dividend that was paid on September 1, 2022.

Warrant Exchange Offer

In August 2022, we announced exchange offers relating to our outstanding Class A Warrants, Class B Warrants, and Class C Warrants. The exchange offers expired in October 2022 and resulted in the issuance of 16,305,984 shares of our common stock in exchange for the cancellation of (i) 4,752,207 Class A Warrants, or approximately 51.4% of the outstanding Class A Warrants, at the time of exchange, (ii) 7,879,030 Class B Warrants, or approximately 64.1% of the outstanding Class B Warrants, at the time of exchange, and (iii) 7,252,004 Class C Warrants, or approximately 64.8% of the outstanding Class C Warrants, at the time of exchange.

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

The global spread of COVID-19 created significant volatility, uncertainty, and economic disruption commencing in 2020, and threatens to continue to do so in 2023. The ongoing pandemic 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 and its variants, or the related significant disruption and volatility in the natural gas and oil markets will have on our business, cash flows, liquidity, financial condition and results of operations, we believe our cost structure and liquidity position us well to address continued price and demand volatility. For additional discussion regarding risks associated with the COVID-19 pandemic, see Item 1A Risk Factors in this report.

Russia’s Invasion of Ukraine; Volatility in Natural Gas, Oil and NGL Prices; and Inflationary Cost Pressures

In late February 2022, Russia launched a military invasion against Ukraine. The Russian invasion has caused, and could intensify, volatility in natural gas, oil and NGL prices, and may have an impact on global growth prospects, which could in turn affect demand for natural gas and oil. This overall uncertainty resulted in stronger commodity prices during much of 2022. Toward the end of 2022, markets began to stabilize, and this, coupled with a milder winter, has resulted in an observed decline in pricing in early 2023. Our 2023 estimated cash flow is partially protected from commodity price volatility due to our current hedge positions that cover approximately 56% of our projected natural gas volumes for 2023. In addition to the recent weakening in commodity prices, the industry is experiencing inflationary pressure, including rising fuel costs, a tightening steel market, and labor and supply chain shortages, which could result in increases to our operating and capital costs that are not fixed. We continue to monitor the situation and assess its impact on our business, including our business partners and customers, as we work to limit our supply chain risk.

Liquidity and Capital Resources

Liquidity Overview

For the 2022 Successor Period, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations and borrowings under our credit agreements, and our primary uses of cash have been for the development of our natural gas and oil properties, acquisitions of additional natural gas properties and return of value to stockholders through dividends and equity repurchases. 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, large portfolio of onshore U.S. unconventional natural gas and liquids assets and 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.

In December 2022, we entered into a New Credit Facility and terminated the Exit Credit Facility, repaying all amounts outstanding and extinguishing all commitments thereunder. We believe our cash flow from operations, cash on hand and borrowing capacity under the New Credit Facility, as discussed below, will provide sufficient liquidity during the next 12 months and the foreseeable future. As of December 31, 2022, we had $1.0 billion of liquidity available, including $130 million of cash on hand and $0.9 billion of aggregate unused borrowing capacity available under the New Credit Facility. As of December 31, 2022, we had $1.05 billion of outstanding borrowings under our New Credit Facility and $35 million utilized for various letters of credit. 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.

Dividends

We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend per share equal to the sum of the Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. Under this base and variable dividend approach, we paid dividends of $1.2 billion, in aggregate, on our common stock in the 2022 Successor Period. See Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

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 the credit agreement governing its New Credit Facility 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 natural gas, oil 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 natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil 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, 2022, our material contractual obligations include repayment of senior notes, outstanding borrowings and interest payment obligations under the New Credit Facility, derivative obligations, asset retirement obligations, lease obligations, capital commitments relating to our investments, 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 natural gas, oil and NGL to move certain of our production to market. The estimated gross undiscounted future commitments under these agreements were approximately $4.3 billion as of December 31, 2022. 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, 18 and 22 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

New Credit Facility

On December 9, 2022, the Company, as borrower, entered into a senior secured reserve-based credit agreement providing for the New Credit Facility which features an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. Subject to certain exceptions, the borrowing base will be redetermined semi-annually on or around April 15 and October 15 of each year. The New Credit Facility provides for a $200 million sublimit available for the issuance of letters of credit and a $50 million sublimit available for swingline loans. Borrowings under the credit agreement may be alternate base rate loans or term SOFR loans, at the Company's election. The New Credit Facility contains certain features that, upon receipt and maintenance of investment grade ratings from S&P, Moody's and/or Fitch and the satisfaction of certain other conditions, result in the removal or relaxation of specified negative and financial covenants, among other favorable adjustments. See Note 6 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 providing for the Exit Credit Facility which featured an initial borrowing base of $2.5 billion. 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 provided for a $200 million sublimit of the aggregate commitments that were available for the issuance of letters of credit. The Exit Credit Facility bore 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 were due to mature 3 years after the Effective Date and the Tranche B Loans were due to mature 4 years after the Effective Date. In December 2022, in conjunction with our entry into the New Credit Facility, the Exit Credit Facility was terminated, repaying all amounts outstanding and extinguishing all commitments thereunder.

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.

Capital Expenditures

For the year ending December 31, 2023, we currently expect to bring or have online approximately 145 to 165 gross wells across 10 to 12 rigs and plan to invest between approximately $1.765 – $1.835 billion in capital expenditures. We expect that approximately 85% of our 2023 capital expenditures will be directed toward our natural gas assets. We currently plan to fund our 2023 capital program through cash on hand, expected cash flow from our operations and borrowings under our New 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 and (Uses) of Cash and Cash Equivalents

The following table presents the sources and uses of our cash and cash equivalents for the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Cash provided by (used in) operating activities	$ 4,125	$ 1,809	$ (21)	$ 1,164
Proceeds from New Credit Facility, net	1,050	—	—	—
Proceeds from issuance of senior notes, net	—	—	1,000	—
Proceeds from issuance of common stock	—	—	600	—
Proceeds from warrant exercise	27	2	—	—
Proceeds from divestitures of property and equipment	407	13	—	150
Proceeds from pre-petition revolving credit facility borrowings, net	—	—	—	339
Capital expenditures	(1,823)	(669)	(66)	(1,142)
Business combination, net	(1,967)	(194)	—	—
Contributions to investments	(18)	—	—	—
Payments on Exit Credit Facility, net	(221)	(50)	(479)	—
Payments on DIP Facility borrowings	—	—	(1,179)	—
Debt issuance and other financing costs	(17)	(3)	(8)	(109)
Cash paid to purchase debt	—	—	—	(94)
Cash paid for common stock dividends	(1,212)	(119)	—	—
Cash paid for preferred stock dividends	—	—	—	(22)
Cash paid to repurchase and retire common stock	(1,073)	—	—	—
Other	—	(1)	—	(13)
Net increase (decrease) in cash, cash equivalents and restricted cash	$ (722)	$ 788	$ (153)	$ 273

Cash Flow from Operating Activities

Cash provided by operating activities was $4.12 billion, $1.81 billion and $1.16 billion in the 2022 Successor Period, 2021 Successor Period and 2020 Predecessor Period, respectively. Cash used in operating activities was $21 million for the 2021 Predecessor Period. The increase in the 2022 Successor Period is primarily due to higher prices for the natural gas, oil and NGL we sold and increased volumes sold due to the Vine Acquisition and Marcellus Acquisition. The increase in the 2021 Successor Period is primarily the result of higher prices for the natural gas, oil 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. Cash flows from operations are largely affected by 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 assets, deferred income taxes and mark-to-market changes in our open derivative instruments. See further discussion below under *Results of Operations*.

Proceeds from New Credit Facility, net

In the 2022 Successor Period, we borrowed a net $1.05 billion under the New Credit Facility. We utilized these borrowings to terminate the Exit Credit Facility, including the repayment of outstanding Tranche A Loans and Tranche B Loans thereunder, backstopping certain letters of credit, and the payment of fees and expenses in connection with the termination of the Exit Credit Facility and entry into the New Credit Facility. A portion of the borrowings under the New Credit Facility were repaid with internally generated cash provided by operating activities.

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. See Note 6 and Note 2 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 2022 Successor Period, we sold our Powder River Basin assets to Continental Resources, Inc. for approximately $450 million, subject to post-close adjustments. 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. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Capital Expenditures

Our capital expenditures significantly increased in the 2022 Successor Period compared to the combined 2021 Successor and Predecessor Periods primarily as a result of increased drilling and completion activity in Haynesville and Marcellus, following the Vine Acquisition and Marcellus Acquisition, respectively. Our capital expenditures 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. In the 2022 Successor Period, our average operated rig count was 14 rigs and 217 spud wells, compared to an average operated rig count of 7 rigs and 121 spud wells in the combined 2021 Successor and Predecessor Periods and 8 rigs and 167 spud wells in the 2020 Predecessor Period. We completed 216 operated wells in the 2022 Successor Period compared to 127 in the combined 2021 Successor and Predecessor Periods and 188 in the 2020 Predecessor Period.

Business Combination, net

In the 2022 Successor Period, we completed the Marcellus Acquisition for approximately $2 billion and 9.4 million shares of our common stock. 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. 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.

Contributions to Investments

During the 2022 Successor Period, we made an initial contribution of $18 million to our investment with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture project. See Note 18 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information.

Payments on Exit Credit Facility, net

In December 2022, we entered into the New Credit Facility and terminated the Exit Credit Facility, repaying all amounts outstanding and extinguishing all commitments thereunder.

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 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.

Debt Issuance and Other Financing Costs

During the 2022 Successor Period, we paid $17 million of one-time fees to lenders to establish the New Credit Facility. 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.

Cash Paid for Common Stock Dividends

As part of our dividend program, we paid common stock base dividends of $256 million and common stock variable dividends of $956 million in the 2022 Successor Period. During the 2021 Successor Period, we paid common stock base dividends of $119 million. See Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Cash Paid for Preferred Stock Dividends

We paid dividends of $22 million on our Predecessor preferred stock during the 2020 Predecessor Period. 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 the Predecessor 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.

Cash Paid to Repurchase and Retire Common Stock

In March 2022, we commenced our share repurchase program, and throughout the 2022 Successor Period, we repurchased 11.7 million shares of our common stock for an aggregate price of $1.1 billion. The shares of common stock that were repurchased during the 2022 Successor Period were retired and recorded as a reduction to common stock and retained earnings.

Results of Operations

Year ended December 31, 2022 compared to the year ended December 31, 2021

Below is a discussion of changes in our results of operations for the 2022 Successor Period compared to the combined 2021 Successor and Predecessor Periods. A discussion of changes in our results of operations for the combined 2021 Successor and Predecessor Periods compared to the 2020 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, 2021 as filed with the SEC on February 24, 2022.

Natural Gas, Oil and NGL Production and Average Sales Prices

	Successor							
	Year Ended December 31, 2022							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,836	6.03	—	—	—	—	1,836	6.03
Haynesville	1,611	5.92	—	—	—	—	1,611	5.92
Eagle Ford	127	5.64	51	96.10	16	36.76	529	11.76
Powder River Basin	10	5.45	2	95.18	1	53.96	26	10.66
Total	3,584	5.96	53	96.07	17	37.48	4,002	6.77
Average NYMEX Price		6.64		94.23				
Average Realized Price (including realized derivatives)		3.67		66.36		37.48		4.32

	Successor							
	Period from February 10, 2021 through December 31, 2021							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,296	3.25	—	—	—	—	1,296	3.25
Haynesville	750	4.10	—	—	—	—	750	4.10
Eagle Ford	137	4.02	60	69.25	19	29.76	608	8.65
Powder River Basin	53	4.33	9	67.90	3	40.00	129	7.69
Total	2,236	3.61	69	69.07	22	31.37	2,783	4.87
Average NYMEX Price		3.97		69.35				
Average Realized Price (including realized derivatives)		2.62		49.06		31.42		3.57

	Predecessor							
	Period from January 1, 2021 through February 9, 2021							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,233	2.42	—	—	—	—	1,233	2.42
Haynesville	543	2.44	—	—	—	—	543	2.44
Eagle Ford	165	2.57	74	53.37	18	23.94	721	6.71
Powder River Basin	61	2.92	10	51.96	4	34.31	144	5.71
Total	2,002	2.45	84	53.21	22	25.92	2,641	3.77
Average NYMEX Price		2.47		52.10				
Average Realized Price (including realized derivatives)		2.52		46.85		25.55		3.65

Natural Gas, Oil and NGL Sales

	Successor			
	Year Ended December 31, 2022			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 4,041	$ —	$ —	$ 4,041
Haynesville	3,481	—	—	3,481
Eagle Ford	261	1,798	212	2,271
Powder River Basin	20	66	13	99
Total natural gas, oil and NGL sales	$ 7,803	$ 1,864	$ 225	$ 9,892

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

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

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

Natural gas, oil and NGL sales in the 2022 Successor Period increased $5.093 billion compared to the combined 2021 Successor and Predecessor Periods. The increase was attributable to a $2.773 billion increase in revenues from higher average prices received. Additionally, an increase of $2.320 billion was due to increased volumes in Marcellus and Haynesville primarily due to the Marcellus Acquisition and the Vine Acquisition, respectively. These increases were partially offset by decreased volumes in Eagle Ford, which was primarily due to a natural decline in production, and the Powder River Basin, following the divestiture of the Powder River Basin assets in March 2022.

Production Expenses

	Successor				Predecessor		Non-GAAP Combined	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 76	0.11	$ 34	0.08	$ 4	0.08	$ 38	0.08
Haynesville	155	0.26	59	0.24	4	0.19	63	0.24
Eagle Ford	234	1.22	173	0.88	21	0.71	194	0.85
Powder River Basin	10	0.94	31	0.74	3	0.56	34	0.72
Total production expenses	$ 475	0.33	$ 297	0.33	$ 32	0.30	$ 329	0.33

Production expenses in the 2022 Successor Period increased $146 million as compared to the combined 2021 Successor and Predecessor Periods. The increase was primarily due to the Vine Acquisition in November 2021 and the Marcellus Acquisition in March 2022. The increase was partially offset by the divestiture of the Powder River Basin in March 2022.

Gathering, Processing and Transportation Expenses ("GP&T")

	Successor				Predecessor		Non-GAAP Combined	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 381	0.57	$ 287	0.68	$ 34	0.70	$ 321	0.68
Haynesville	313	0.53	118	0.49	11	0.49	129	0.49
Eagle Ford	343	1.78	290	1.46	45	1.55	335	1.48
Powder River Basin	22	2.32	85	2.03	12	2.09	97	2.04
Total GP&T	$ 1,059	0.73	$ 780	0.86	$ 102	0.96	$ 882	0.87

Gathering, processing and transportation expenses in the 2022 Successor Period increased $177 million as compared to the combined 2021 Successor and Predecessor Periods. Haynesville increased $184 million primarily due to the Vine Acquisition in November 2021 and increased cost due to higher commodity prices. Marcellus increased $113 million primarily due to the Marcellus Acquisition in March 2022, partially offset by a decrease of $53 million primarily due to lower rates. Eagle Ford increased $70 million due to increased rates with higher commodity prices, which was partially offset by a decrease of $62 million due to reduced volumes primarily due to a natural decline in production. Powder River Basin decreased by $75 million due to the divestiture in March 2022.

Severance and Ad Valorem Taxes

	Successor				Predecessor		Non-GAAP Combined	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 17	0.03	$ 9	0.02	$ 1	0.01	$ 10	0.02
Haynesville	75	0.13	22	0.09	2	0.09	24	0.09
Eagle Ford	139	0.71	96	0.48	13	0.45	109	0.48
Powder River Basin	11	1.09	31	0.75	2	0.48	33	0.70
Total severance and ad valorem taxes	$ 242	0.17	$ 158	0.17	$ 18	0.17	$ 176	0.17

Severance and ad valorem taxes in the 2022 Successor Period increased $66 million as compared to the combined 2021 Successor and Predecessor Periods. Higher commodity prices and increases to the Haynesville statutory severance tax rates in the 2022 Successor Period drove $42 million of the increase, and an additional $46 million increase was the result of the Vine Acquisition and Marcellus Acquisition. These increases were partially offset by a $22 million decrease attributable to the divestiture of the Powder River Basin in March 2022.

Adjusted Gross Margin by Operating Area

The table below presents the adjusted gross margin for each of our operating areas. Adjusted gross margin is defined as natural gas, oil and NGL sales less production expenses, gathering, processing and transportation expenses, and severance and ad valorem taxes. Adjusted gross margin is a non-GAAP measure, and a reconciliation of gross margin to adjusted gross margin is presented within the "Non-GAAP Measures" section of this Item 7.

	Successor				Predecessor		Non-GAAP Combined	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021		Year Ended December 31, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 3,567	5.32	$ 1,040	2.47	$ 80	1.63	$ 1,120	2.38
Haynesville	2,938	5.00	799	3.28	36	1.67	835	3.14
Eagle Ford	1,555	8.05	1,153	5.83	114	4.00	1,267	5.59
Powder River Basin	56	6.31	174	4.17	16	2.58	190	3.98
Adjusted gross margin	$ 8,116	5.54	$ 3,166	3.51	$ 246	2.34	$ 3,412	3.38

Natural Gas and Oil Derivatives

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Natural gas derivatives - realized gains (losses)	$ (2,998)	$ (715)	$ 6
Natural gas derivatives - unrealized gains (losses)	611	70	(179)
Total losses on natural gas derivatives	$ (2,387)	$ (645)	$ (173)
Oil derivatives - realized losses	$ (576)	$ (453)	$ (19)
Oil derivatives - unrealized gains (losses)	283	(29)	(190)
Total losses on oil derivatives	(293)	(482)	(209)
Total losses on natural gas and oil derivatives	$ (2,680)	$ (1,127)	$ (382)

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
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Marketing revenues	$ 4,231	$ 2,263	$ 239
Marketing expenses	4,215	2,257	237
Marketing margin	$ 16	$ 6	$ 2

Marketing revenues and expenses increased in the 2022 Successor Period as a result of increased natural gas, oil and NGL prices received in our marketing operation. Additionally, during the 2022 Successor Period, marketing revenues and expenses increased due to increased volumes from the Vine Acquisition and Marcellus Acquisition.

Exploration Expenses

During the 2022 Successor Period, exploration expense charges of $23 million were primarily the result of non-cash impairment charges in unproved properties of $8 million, $6 million of charges related to dry hole expense and $6 million of geological and geophysical expense. We did not have material exploration expenses during the 2021 Successor Period or 2021 Predecessor Period.

General and Administrative Expenses

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Total G&A, net	$ 142	$ 97	$ 21
G&A, net per Mcfe	$ 0.10	$ 0.11	$ 0.20

Total general and administrative expenses, net during the 2022 Successor Period increased $24 million compared to the combined 2021 Successor and Predecessor Periods primarily due to adjustments in employee benefits and timing of stock award grants, as well as increases in transaction-related fees.

Separation and Other Termination Costs

During the 2022 Successor Period, 2021 Successor Period and 2021 Predecessor Period, we recognized $5 million, $11 million and $22 million, respectively, of separation and other termination costs related to one-time termination benefits for certain employees.

Depreciation, Depletion and Amortization

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
DD&A	$ 1,753	$ 919	$ 72
DD&A per Mcfe	$ 1.20	$ 1.02	$ 0.68

The absolute and per unit increases in depreciation, depletion and amortization for the 2022 Successor Period compared to the combined 2021 Successor and Predecessor Periods, are primarily the result of the Vine Acquisition and Marcellus Acquisition.

Other Operating Expense (Income), Net

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Other operating expense (income), net	$ 49	$ 84	$ (12)

During the 2022 Successor Period, we recognized approximately $41 million of costs related to our Marcellus Acquisition, which included integration costs, consulting fees, financial advisory fees, legal fees and change in control expense in accordance with Chief's existing employment agreements. In the 2021 Successor Period we recognized approximately $59 million of costs related to the Vine Acquisition, 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.

Interest Expense

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Interest expense on debt	$ 181	$ 79	$ 11
Other	13	—	—
Amortization of premium, issuance costs and other	(3)	5	—
Capitalized interest	(31)	(11)	—
Total interest expense	$ 160	$ 73	$ 11

The increase in total interest expense in the 2022 Successor Period compared to the combined 2021 Successor and Predecessor Periods, was primarily due to the increase in outstanding debt obligations between periods. In November 2021, we assumed Vine's $950 million of senior notes as part of the Vine Acquisition, and during the 2022 Successor Period, we had increased borrowings under our various credit agreements, compared to the combined 2021 Successor and Predecessor Periods. During the 2022 Successor Period, borrowings under our credit agreements had an average interest rate of 8.7%. Additionally, $12 million of interest expense was recorded during the 2022 Successor Period pertaining to a tax interest assessment.

Reorganization Items, Net

	Predecessor
	Period from January 1, 2021 through February 9, 2021
Gains on the settlement of liabilities subject to compromise	$ 6,443
Accrual for allowed claims	(1,002)
Gain on fresh start adjustments	201
Gain from release of commitment liabilities	55
Professional service provider fees and other	(60)
Success fees for professional service providers	(38)
Surrender of other receivable	(18)
FLLO alternative transaction fee	(12)
Total reorganization items, net	$ 5,569

In the 2021 Predecessor Period, we recorded a net gain of $5.569 billion 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. We did not have any reorganization items, net for the 2022 Successor Period or the 2021 Successor Period.

Income Tax Expense (Benefit). We recorded an income tax benefit of $1.3 billion in the 2022 Successor Period. In the 2021 Successor and Predecessor Periods, we recorded an income tax benefit of $49 million and $57 million, respectively. Of the $1.3 billion of income tax benefit recorded in the 2022 Successor Period, $1.4 billion is related to the partial release of the valuation allowance, which is partially offset by $47 million in current federal and state income taxes. 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. 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).

Non-GAAP Measures

Management uses adjusted gross margin to assess our operating results and financial performance across assets and periods. We define adjusted gross margin as natural gas, oil and NGL sales less production expenses, gathering, processing and transportation expenses, and severance and ad valorem taxes.

Adjusted gross margin is not a measure of financial performance under GAAP and should not be considered in isolation or as a substitute for analysis of our results reported under GAAP. Additionally, adjusted gross margin may not be comparable to similarly titled measures used by other companies. We exclude depreciation, depletion and amortization from the calculation of adjusted gross margin as depreciation, depletion and amortization are non-cash expenses that do not necessarily reflect present-day performance. The table below reconciles gross margin, as defined by GAAP, to adjusted gross margin.

	Successor		Predecessor	Non-GAAP Combined
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2021
Gross margin (GAAP)				
Natural gas, oil and NGL sales	$ 9,892	$ 4,401	$ 398	$ 4,799
Less:				
Production expenses	(475)	(297)	(32)	(329)
Gathering, processing and transportation expenses	(1,059)	(780)	(102)	(882)
Severance and ad valorem taxes	(242)	(158)	(18)	(176)
Depreciation, depletion and amortization	(1,753)	(919)	(72)	(991)
Gross margin (GAAP)	6,363	2,247	174	2,421
Add back: Depreciation, depletion and amortization	1,753	919	72	991
Adjusted gross margin (Non-GAAP)	$ 8,116	$ 3,166	$ 246	$ 3,412

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.

Natural Gas and Oil Reserves. Estimates of natural gas and oil 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 natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See *Supplemental Disclosures About Natural Gas, Oil 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 natural gas and oil properties, which are accounted for under the successful efforts accounting method. The Company determines the fair value of acquired natural gas and oil 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.

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, one source of evidence is a projection of income exclusive of existing timing differences.

Our judgement regarding the realizability of deferred tax assets is thus partially affected by estimates of future financial condition.

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.

Impairments. Long-lived assets used in operations, including proved gas and oil 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 natural gas and crude oil 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.

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.

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 natural gas, oil 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 natural gas, oil 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 natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil 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 2022 Successor Period, natural gas, oil and NGL revenues, excluding any effect of our derivative instruments, were $7.803 billion, $1.864 billion, and $225 million, respectively. Based on production, natural gas, oil and NGL revenue for the 2022 Successor Period would have increased or decreased by approximately $780 million, $186 million, and $23 million, respectively, for each 10% increase or decrease in prices. As of December 31, 2022, the fair values of our natural gas and oil derivatives were net liabilities of $501 million and $24 million, respectively. A 10% increase in forward natural gas prices would decrease the valuation of natural gas derivatives by approximately $324 million, while a 10% decrease would increase the valuation by $321 million. A 10% increase in forward oil prices would decrease the valuation of oil derivatives by $22 million, while a 10% decrease would increase the valuation by $22 million. This fair value change assumes volatility based on prevailing market parameters at December 31, 2022. 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 New Credit Facility and Exit Credit Facility for the 2022 Successor Period, the Exit Credit Facility for the 2021 Successor Period and the pre-petition revolving credit facility and DIP Facility for the 2021 and 2020 Predecessor Periods. Interest is payable on borrowings under these credit agreements 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, 2022, we had $1.05 billion of outstanding borrowings under our New Credit Facility. A 1.0% increase in interest rates based on the variable borrowings as of December 31, 2022 would result in an increase in our interest expense of approximately $11 million per year.

Item 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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 sheets of Chesapeake Energy Corporation and its subsidiaries (Successor) (the "Company") as of December 31, 2022 and 2021, and the related consolidated statements of operations, of comprehensive income (loss), of stockholders' equity and of cash flows for the year ended December 31, 2022 and 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for the year ended December 31, 2022 and 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, 2022, 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 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 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, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits 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 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. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 Natural Gas and Oil Reserves on Proved Natural Gas and Oil Properties, Net

As described in Note 1 to the consolidated financial statements, the Company's property and equipment, net balance was approximately $11.2 billion as of December 31, 2022, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2022 was approximately $1.8 billion, both of which substantially related to proved natural gas and oil properties. The Company follows the successful efforts method of accounting for its natural gas and oil properties. Under this method, all capitalized well costs and leasehold costs of proved natural gas and oil 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 natural gas and oil 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 natural gas and oil reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved natural gas and oil reserves on proved natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil reserves. The work of management's specialists was used in performing procedures to evaluate the reasonableness of the proved natural gas and oil 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 evaluating the methods and assumptions used by the specialists, testing the completeness and accuracy of the data used by the specialists, and evaluating 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.

Marcellus Acquisition - Valuation of Proved and Unproved Natural Gas and Oil Properties

As described in Note 4 to the consolidated financial statements, on March 9, 2022, the Company completed the Marcellus Acquisition. Accordingly, the Company recorded the estimated fair values of the acquired proved natural gas and oil properties of approximately $2.3 billion and $788 million for unproved properties, respectively. As disclosed by management, management determines the fair value of acquired natural gas and oil 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 and unproved natural gas and oil reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the valuation of proved and unproved natural gas and oil properties in the Marcellus Acquisition is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fair value estimate of the proved and unproved natural gas and oil properties acquired, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management's significant inputs 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 testing the effectiveness of controls relating to acquisition accounting, including controls over the valuation of proved and unproved natural gas and oil properties acquired. These procedures also included, among others (i) reading the purchase agreement; (ii) testing management's process for developing the fair value estimate of proved and unproved natural gas and oil properties acquired; (iii) evaluating the appropriateness of the discounted cash flow models; (iv) testing the completeness and accuracy of underlying data used in the discounted cash flow models; and (v) evaluating the reasonableness of the significant inputs 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 significant inputs related to future commodity prices escalated by an inflationary rate after five years, 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 significant inputs were consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing procedures to evaluate the reasonableness of the recoverable reserves and production rates used in the discounted cash flow models. 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 evaluating the methods and assumptions used by the specialists, testing the completeness and accuracy of the data used by the specialists, and evaluating the specialists' findings. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and the reasonableness of the market-based weighted average cost of capital by operating area.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 22, 2023

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 statements of operations, of comprehensive income (loss), of stockholders' equity and of cash flows of Chesapeake Energy Corporation and its subsidiaries (Predecessor) (the "Company") for the period from January 1, 2021 through February 9, 2021 and for the year ended December 31, 2020, 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 results of operations and cash flows of the Company for the period from January 1, 2021 through February 9, 2021 and for the year ended December 31, 2020 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 as of February 9, 2021.

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 audit 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.

/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	
($ in millions, except per share data)	December 31, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 130	$ 905
Restricted cash	62	9
Accounts receivable, net	1,438	1,115
Short-term derivative assets	34	5
Assets held for sale	819	—
Other current assets	215	69
Total current assets	2,698	2,103
Property and equipment:		
Natural gas and oil properties, successful efforts method		
Proved natural gas and oil properties	11,096	7,682
Unproved properties	2,022	1,530
Other property and equipment	500	495
Total property and equipment	13,618	9,707
Less: accumulated depreciation, depletion and amortization	(2,431)	(908)
Property and equipment held for sale, net	—	3
Total property and equipment, net	11,187	8,802
Long-term derivative assets	47	—
Deferred income tax assets	1,351	—
Other long-term assets	185	104
Total assets	$ 15,468	$ 11,009
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 603	$ 308
Accrued interest	42	38
Short-term derivative liabilities	432	899
Other current liabilities	1,627	1,202
Total current liabilities	2,704	2,447
Long-term debt, net	3,093	2,278
Long-term derivative liabilities	174	249
Asset retirement obligations, net of current portion	323	349
Other long-term liabilities	50	15
Total liabilities	6,344	5,338
Contingencies and commitments (Note 7)		
Stockholders' equity:		
Successor common stock, $0.01 par value, 450,000,000 shares authorized: 134,715,094 and 117,917,349 shares issued	1	1
Successor additional paid-in capital	5,724	4,845
Retained earnings	3,399	825
Total stockholders' equity	9,124	5,671
Total liabilities and stockholders' equity	$ 15,468	$ 11,009

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

TABLE OF CONTENTS

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor		Predecessor	
($ in millions except per share data)	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Revenues and other:				
Natural gas, oil and NGL	$ 9,892	$ 4,401	$ 398	$ 2,745
Marketing	4,231	2,263	239	1,869
Natural gas and oil derivatives	(2,680)	(1,127)	(382)	596
Gains on sales of assets	300	12	5	30
Total revenues and other	11,743	5,549	260	5,240
Operating expenses:				
Production	475	297	32	373
Gathering, processing and transportation	1,059	780	102	1,082
Severance and ad valorem taxes	242	158	18	149
Exploration	23	7	2	427
Marketing	4,215	2,257	237	1,889
General and administrative	142	97	21	267
Separation and other termination costs	5	11	22	44
Depreciation, depletion and amortization	1,753	919	72	1,097
Impairments	—	1	—	8,535
Other operating expense (income), net	49	84	(12)	80
Total operating expenses	7,963	4,611	494	13,943
Income (loss) from operations	3,780	938	(234)	(8,703)
Other income (expense):				
Interest expense	(160)	(73)	(11)	(331)
Gains (losses) on purchases, exchanges or extinguishments of debt	(5)	—	—	65
Other income (expense)	36	31	2	(4)
Reorganization items, net	—	—	5,569	(796)
Total other income (expense)	(129)	(42)	5,560	(1,066)
Income (loss) before income taxes	3,651	896	5,326	(9,769)
Income tax benefit	(1,285)	(49)	(57)	(19)
Net income (loss)	4,936	945	5,383	(9,750)
Net loss attributable to noncontrolling interests	—	—	—	16
Net income (loss) available to Chesapeake	4,936	945	5,383	(9,734)
Deemed dividend on warrants	(67)	—	—	—
Preferred stock dividends	—	—	—	(22)
Net income (loss) available to common stockholders	$ 4,869	$ 945	$ 5,383	$ (9,756)
Earnings (loss) per common share:				
Basic	$ 38.71	$ 9.29	$ 550.35	$ (998.26)
Diluted	$ 33.36	$ 8.12	$ 534.51	$ (998.26)
Weighted average common shares outstanding (in thousands):				
Basic	125,785	101,754	9,781	9,773
Diluted	145,961	116,341	10,071	9,773

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

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

($ in millions)	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Net income (loss)	$ 4,936	$ 945	$ 5,383	$ (9,750)
Other comprehensive income, net of income tax:				
Reclassification of losses on settled derivative instruments[(a)]	—	—	3	33
Other comprehensive income	—	—	3	33
Comprehensive income (loss)	4,936	945	5,386	(9,717)
Comprehensive loss attributable to noncontrolling interests	—	—	—	16
Comprehensive income (loss) attributable to Chesapeake	$ 4,936	$ 945	$ 5,386	$ (9,701)

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

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in millions)	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Cash flows from operating activities:				
Net income (loss)	$ 4,936	$ 945	$ 5,383	$ (9,750)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	1,753	919	72	1,097
Deferred income tax benefit	(1,332)	(49)	(57)	(10)
Derivative (gains) losses, net	2,680	1,127	382	(596)
Cash receipts (payments) on derivative settlements, net	(3,561)	(1,142)	(17)	884
Share-based compensation	22	9	3	21
Gains on sales of assets	(300)	(12)	(5)	(30)
Impairments	—	1	—	8,535
Non-cash reorganization items, net	—	—	(6,680)	(213)
Exploration	14	2	2	417
(Gains) losses on purchases, exchanges or extinguishments of debt	5	—	—	(65)
Other	31	46	45	(41)
Changes in assets and liabilities	(123)	(37)	851	915
Net cash provided by (used in) operating activities	4,125	1,809	(21)	1,164
Cash flows from investing activities:				
Capital expenditures	(1,823)	(669)	(66)	(1,142)
Business combination, net	(1,967)	(194)	—	—
Contributions to investments	(18)	—	—	—
Proceeds from divestitures of property and equipment	407	13	—	150
Net cash used in investing activities	(3,401)	(850)	(66)	(992)
Cash flows from financing activities:				
Proceeds from New Credit Facility	1,600	—	—	—
Payments on New Credit Facility	(550)	—	—	—
Proceeds from Exit Credit Facility	9,583	30	—	—
Payments on Exit Credit Facility	(9,804)	(80)	(479)	—
Proceeds from pre-petition revolving credit facility borrowings	—	—	—	3,656
Payments on pre-petition revolving credit facility borrowings	—	—	—	(3,317)
Proceeds from DIP Facility borrowings	—	—	—	60
Payments on DIP Facility borrowings	—	—	(1,179)	(60)
Proceeds from issuance of senior notes, net	—	—	1,000	—
Proceeds from issuance of common stock	—	—	600	—
Proceeds from warrant exercise	27	2	—	—
Debt issuance and other financing costs	(17)	(3)	(8)	(109)
Cash paid to repurchase and retire common stock	(1,073)	—	—	—
Cash paid to purchase debt	—	—	—	(94)
Cash paid for common stock dividends	(1,212)	(119)	—	—
Cash paid for preferred stock dividends	—	—	—	(22)
Other	—	(1)	—	(13)
Net cash provided by (used in) financing activities	(1,446)	(171)	(66)	101
Net increase (decrease) in cash, cash equivalents and restricted cash	(722)	788	(153)	273
Cash, cash equivalents and restricted cash, beginning of period	914	126	279	6
Cash, cash equivalents and restricted cash, end of period	$ 192	$ 914	$ 126	$ 279

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	
($ in millions)	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Cash and cash equivalents	$ 130	$ 905	$ 40	$ 279
Restricted cash	62	9	86	—
Total cash, cash equivalents and restricted cash	$ 192	$ 914	$ 126	$ 279

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

	Successor		Predecessor	
($ in millions)	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Supplemental cash flow information:				
Cash paid for reorganization items, net	$ —	$ 65	$ 66	$ 140
Interest paid, net of capitalized interest	$ 146	$ 34	$ 13	$ 224
Income taxes paid, net of refunds received	$ 193	$ (9)	$ —	$ —
Supplemental disclosure of significant non-cash investing and financing activities:				
Change in accrued drilling and completion costs	$ 148	$ 30	$ (5)	$ (216)
Put option premium on equity backstop agreement	$ —	$ —	$ 60	$ 60
Common stock issued for business combination	$ 764	$ 1,232	$ —	$ —
Operating lease obligations recognized	$ 120	$ —	$ —	$ 32

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Attributable to Chesapeake									
	Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Treasury Stock	Non-controlling Interest	Total Stockholders' Equity (Deficit)
($ in millions)	Shares	Amount	Shares	Amount						
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
Issuance of common stock for Marcellus Acquisition	—	—	9,442,185	—	764	—	—	—	—	764
Share-based compensation	—	—	174,740	—	21	—	—	—	—	21
Issuance of common stock for warrant exchange offer	—	—	16,305,984	—	67	—	—	—	—	67
Issuance of common stock for warrant exercise	—	—	2,102,244	—	27	—	—	—	—	27
Issuance of reserved common stock and warrants	—	—	439,370	—	—	—	—	—	—	—
Repurchase and retirement of common stock	—	—	(11,666,778)	—	—	(1,073)	—	—	—	(1,073)
Net income	—	—	—	—	—	4,936	—	—	—	4,936
Dividends on common stock	—	—	—	—	—	(1,222)	—	—	—	(1,222)
Deemed dividend on warrants	—	—	—	—	—	(67)	—	—	—	(67)
Balance as of December 31, 2022 (Successor)	—	$ —	134,715,094	$ 1	$ 5,724	$ 3,399	$ —	$ —	$ —	$ 9,124

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	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Treasury Stock	Non-controlling Interest	Total Stockholders' Equity (Deficit)
($ in millions)	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 available 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)
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

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 a natural gas and oil exploration and production company engaged in the acquisition, exploration and development of properties for the production of natural gas, oil 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. All monetary values, other than per unit and per share amounts, are stated in millions of U.S. dollars unless otherwise specified.

This Annual Report on Form 10-K (this "Form 10-K") relates to the financial position of the Successor as of December 31, 2022 and as of December 31, 2021, and the year ended December 31, 2022 ("2022 Successor Period"), 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 year ended December 31, 2020 ("2020 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. 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 natural gas and oil properties, natural gas and oil reserves, derivatives, income taxes, 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. See Note 18 for further discussion of our investments. Undivided interests in natural gas and oil 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, 2022, we had restricted cash of $62 million. Our restricted cash represents funds legally restricted for payment of certain convenience class unsecured claims following our emergence from bankruptcy, as well as for future payment of certain royalties.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas, oil 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 additional information regarding our accounts receivable.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for our natural gas and oil 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 natural gas and oil 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 gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and crude oil 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, computers and office equipment, land and other assets that support our operations. 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.

Assets Held for Sale

We may market certain non-core natural gas and oil assets or other properties for sale. At the end of each reporting period, we evaluate if these assets should be classified as held for sale. The held for sale criteria includes the following: management commits to a plan to sell, the asset is available for immediate sale, an active program to locate a buyer exists, the sale of the asset is probable and expected to be completed within a year, the asset is actively being marketed for sale and that it is unlikely that significant changes to the plan will be made. If each of the criteria are met, then the assets and associated liabilities are classified as held for sale. As of December 31, 2022, the asset and liabilities held for sale are in connection with the portion of the Eagle Ford assets for which we have entered into an agreement to sell to WildFire Energy I LLC. See Note 23 for further discussion.

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, 2022 and as of December 31, 2021 are liabilities of approximately $150 million and $23 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts.

Debt Issuance Costs

Costs associated with the arrangement of our credit facilities are included in other long-term assets and are amortized over the life of the facility using the straight-line method. As of December 31, 2022, these costs were $24 million. Upon the termination of the Exit Credit Facility, we recognized $5 million of losses on purchases, exchanges or extinguishment of debt relating to lenders who had previously participated in the Exit Credit Facility that chose not to participate in the New Credit Facility. 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 straight-line method. Unamortized issuance costs associated with the Successor senior notes as of December 31, 2022 totaled $7 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 natural gas and oil properties, this is the period in which a natural gas or oil 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 natural gas and oil properties. See Note 22 for further discussion of asset retirement obligations.

Revenue Recognition

Revenue from the sale of natural gas, oil 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 natural gas, oil and NGL production (recorded as natural gas, oil 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 natural gas, oil 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. See Note 10 for a presentation of the disaggregation of revenue.

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 natural gas, oil 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 natural gas, oil and NGL marketing activities are presented on a net basis.

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, 2022, 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 12 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 and performance share 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. Forfeitures on our share-based compensation awards are recognized as they occur. 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 natural gas and oil leasehold and development activities, these amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil 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.

2. Chapter 11 Emergence

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 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, warrant agreements 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 an equity interest in the Predecessor, including the Predecessor's 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 Chairman of the Board, Michael Wichterich, and five non-employee directors, Timothy S. Duncan, Benjamin C. Duster, IV, Sarah A. Emerson, Matthew M. Gallagher and Brian Steck.

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

Natural gas and oil properties. The Company's principal assets are its natural gas and oil properties, which are accounted for under the successful efforts accounting method. The Company determined the fair value of its natural gas and oil 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 the 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 were based on prevailing market rates.

Asset retirement obligations. The fair value of the Company's asset retirement obligations was revalued based upon estimated 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:				
Natural gas and oil properties, successful efforts method				
Proved natural gas and oil 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) Reflects 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 natural gas and oil 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 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.

We did not have any reorganization items, net for the 2022 Successor Period or the 2021 Successor Period. The following table summarizes the components in reorganization items, net included in our consolidated statements of operations:

	Predecessor	
	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)

4. Natural Gas and Oil Property Transactions

Marcellus Acquisition

On March 9, 2022, we completed the acquisition of Chief and associated non-operated interests held by affiliates of Tug Hill, Inc. of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania ("Marcellus Acquisition") for total consideration of approximately $2.77 billion, consisting of approximately $2 billion in cash, including working capital adjustments and approximately 9.4 million shares of our common stock, to acquire high quality producing assets and a deep inventory of premium drilling locations in the prolific Marcellus Shale in Northeast Pennsylvania. The Marcellus Acquisition was indebtedness free, effective as of January 1, 2022 and was subject to customary purchase price adjustments. We funded the cash portion of the consideration with cash on hand and $914 million of borrowings under the Company's Exit Credit Facility. See Note 6 for further discussion of debt.

Marcellus Acquisition Purchase Price Allocation

We have accounted for the Marcellus Acquisition as a business combination, using the acquisition method. The following table represents the allocation of the total purchase price to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date. We finalized the acquisition accounting for this transaction during the 2022 Successor Period, which resulted in measurement period adjustments of $39 million to both restricted cash and current liabilities, to reflect funds restricted for future payment of certain royalties.

	Purchase Price Allocation
Consideration:	
Cash	$ 2,000
Fair value of Chesapeake's common stock issued in the merger [a]	764
Working capital adjustments	6
Total consideration	$ 2,770
Fair Value of Liabilities Assumed:	
Current liabilities	$ 459
Other long-term liabilities	129
Amounts attributable to liabilities assumed	$ 588
Fair Value of Assets Acquired:	
Cash, cash equivalents and restricted cash	$ 39
Other current assets	218
Proved natural gas and oil properties	2,309
Unproved properties	788
Other property and equipment	1
Other long-term assets	3
Amounts attributable to assets acquired	$ 3,358
Total identifiable net assets	$ 2,770

(a) The fair value of our common stock is a Level 1 input, as our stock price is a quoted price in an active market as of the acquisition date.

Natural Gas and Oil Properties

For the Marcellus 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 natural gas and oil properties as of the acquisition date was based on estimated natural gas and oil 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 natural gas and oil properties acquired. Additionally, the fair value estimate of proved and unproved natural gas and oil properties was corroborated by utilizing a market approach, which considers recent comparable transactions for similar assets.

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

Marcellus Acquisition Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations natural gas, oil and NGL revenues of $1,331 million, marketing revenues of $20 million, net losses on natural gas and oil derivatives of $379 million, and direct operating expenses of $483 million, including depreciation, depletion and amortization, related to the Marcellus Acquisition businesses for the period from March 10, 2022 (the date immediately following the completion of the Marcellus Acquisition) through December 31, 2022.

Vine Acquisition

On November 1, 2021, we acquired 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.

Vine Purchase Price Allocation

We have accounted for the Vine Acquisition as a business combination, using the acquisition method. The following table represents the 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. We finalized the acquisition accounting for this transaction during the 2022 Successor Period, which resulted in measurement period adjustments of $19 million to both deferred tax liabilities and unproved properties. See Note 11 for additional information regarding the change to deferred tax liabilities.

		Purchase Price Allocation
Consideration:		
Cash	$	253
Fair value of Chesapeake's common stock issued in the merger [(a)]		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		30
Other long-term liabilities		272
Amounts attributable to liabilities assumed	$	2,088
Fair Value of Assets Acquired:		
Cash and cash equivalents	$	59
Other current assets		206
Proved natural gas and oil properties		2,181
Unproved properties		1,099
Other property and equipment		1
Other long-term assets		32
Amounts attributable to assets acquired	$	3,578
Total identifiable net assets	$	1,490

(a) The fair value of our common stock is a Level 1 input, as our stock price is a quoted price in an active market as of the acquisition date.

Natural Gas and Oil 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 natural gas and oil properties as of the acquisition date was based on estimated natural gas and oil 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 natural gas and oil properties acquired. Additionally, the fair value estimate of proved and unproved natural gas and oil properties was corroborated by utilizing a market approach, which considers recent comparable transactions for similar assets.

The inputs used to value natural gas and oil 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 natural gas, oil and NGL revenues of $290 million, net gains on natural gas and oil 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. We included in our consolidated statements of operations natural gas, oil and NGL revenues of $1,863 million, net losses on natural gas and oil derivatives of $624 million, direct operating expenses of $924 million, including depreciation, depletion and amortization, and other expense of $39 million related to the Vine business for the 2022 Successor Period.

Combined Pro Forma Financial Information

As the Vine Acquisition closed on November 1, 2021, all activity in 2022 is included in Chesapeake's consolidated statements of operations for the 2022 Successor Period. The following unaudited pro forma financial information is based on our historical consolidated financial statements adjusted to reflect as if the Marcellus Acquisition and Vine Acquisition had each occurred on February 10, 2021, the date Chesapeake emerged from bankruptcy. See Note 2 for additional information on the bankruptcy. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including the estimated tax impact of the pro forma adjustments.

	Successor	
	Year Ended December 31, 2022	**Period from February 10, 2021 through December 31, 2021**
Revenues	$ 11,743	$ 5,891
Net income (loss) available to common stockholders	$ 4,765	$ (5)
Earnings (loss) per common share:		
Basic	$ 37.37	$ (0.04)
Diluted	$ 32.26	$ (0.04)

Powder River Divestiture

On January 24, 2022, Chesapeake signed an agreement to sell its Powder River Basin assets in Wyoming to Continental Resources, Inc. for approximately $450 million, subject to customary closing adjustments. The divestiture, which closed on March 25, 2022, resulted in the recognition of a gain of approximately $293 million, which included $13 million of post-close adjustments, based on the difference between the carrying value of the assets and the cash received.

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.

5. Earnings Per Share

Basic earnings (loss) per common share is computed by dividing the net income (loss) available 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 units, 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	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Numerator				
Net income (loss) available to common stockholders, basic and diluted	$ 4,869	$ 945	$ 5,383	$ (9,756)
Denominator (in thousands)				
Weighted average common shares outstanding, basic	125,785	101,754	9,781	9,773
Effect of potentially dilutive securities				
Preferred stock	—	—	290	—
Warrants	19,734	14,376	—	—
Restricted stock units	395	200	—	—
Performance share units	47	11	—	—
Weighted average common shares outstanding, diluted	145,961	116,341	10,071	9,773
Earnings (loss) per common share:				
Basic	$ 38.71	$ 9.29	$ 550.35	$ (998.26)
Diluted	$ 33.36	$ 8.12	$ 534.51	$ (998.26)

Successor

During the 2022 and 2021 Successor Periods, the diluted earnings per share calculation excludes the effect of 789,458 and 1,228,828 reserved shares of common stock and 1,489,337 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 for such shares to be considered dilutive shares during the 2022 and 2021 Successor Periods, respectively.

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.

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, 2022 and 2021:

	Successor			
	December 31, 2022		December 31, 2021	
	Carrying Amount	Fair Value[a]	Carrying Amount	Fair Value[a]
New Credit Facility	$ 1,050	$ 1,050	$ —	$ —
Exit Credit Facility - Tranche A Loans	—	—	—	—
Exit Credit Facility - Tranche B Loans	—	—	221	221
5.50% senior notes due 2026	500	485	500	526
5.875% senior notes due 2029	500	475	500	535
6.75% senior notes due 2029[b]	950	917	950	1,031
Premiums on senior notes	100	—	116	—
Debt issuance costs	(7)	—	(9)	—
Total long-term debt, net	$ 3,093	$ 2,927	$ 2,278	$ 2,313

(a) The carrying value of borrowings under each respective Credit Facility approximates 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.

The table below presents debt maturities as of December 31, 2022, excluding debt issuance costs and premiums:

	Total
2023	$ —
2024	—
2025	—
2026	500
2027	1,050
Thereafter	1,450
Total long-term debt, net	$ 3,000

New Credit Facility. In December 2022, we entered into a senior secured reserve-based credit agreement (the "New Credit Agreement") with the lenders and issuing banks party thereto (the "Lenders"), and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (in such capacity, the "Administrative Agent"), providing for a reserve-based credit facility (the "New Credit Facility") with an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. The New Credit Facility matures in December 2027. The New Credit Facility provides for a $200.0 million sublimit available for the issuance of letters of credit and a $50.0 million sublimit available for swingline loans.

Initially, the obligations under the New Credit Facility are guaranteed by certain of Chesapeake's subsidiaries (the "Guarantors"), and the New Credit Facility is secured by substantially all of the assets owned by the Company and the Guarantors (subject to customary exceptions), including mortgages on not less than 85% of the total PV-9 of the borrowing base properties evaluated in the most recent reserve report (where PV-9 is the net present value, discounted at 9% per annum, of the estimated future net revenues). The borrowing base will be redetermined semi-annually on or around April 15 and October 15 of each year, with one interim "wildcard" redetermination available to each of the Company and the Administrative Agent, the latter at the direction of the Required Lenders (as defined in the New Credit Agreement), between scheduled redeterminations. The next scheduled redetermination will be on or about April 15, 2023. The New Credit Agreement contains restrictive covenants that limit Chesapeake and its subsidiaries' ability to, among other things but subject to exceptions customary to reserve-based credit facilities: (i) incur additional indebtedness, (ii) make investments, (iii) enter into mergers; (iv) make or declare dividends; (v) repurchase or redeem certain indebtedness; (vi) enter into certain hedges; (vii) incur liens; (viii) sell assets; and (ix) engage in certain transactions with affiliates. The New Credit Agreement requires Chesapeake to maintain compliance with the following financial ratios ("Financial Covenants") beginning with the first quarter of 2023: (A) a current ratio, which is the ratio of Chesapeake's and its restricted subsidiaries' consolidated current assets (including unused commitments under the New Credit Facility but excluding certain non-cash assets) to their consolidated current liabilities (excluding the current portion of long-term debt and certain non-cash liabilities), of not less than 1.00 to 1.00; (B) a net leverage ratio, which is the ratio of total indebtedness (less unrestricted cash up to a specified threshold) to Consolidated EBITDAX (as defined in the Credit Agreement) for the prior four fiscal quarters, of not greater than 3.50 to 1.00 and (C) a PV-9 coverage ratio of the net present value, discounted at 9% per annum, of the estimated future net revenues expected in the proved reserves to Chesapeake's and its restricted subsidiaries' total indebtedness of not less than 1.50 to 1.00 ("PV-9 Coverage Ratio").

Borrowings under the New Credit Agreement may be alternate base rate loans or term SOFR loans, at our election. Interest is payable quarterly for alternate base rate loans and at the end of the applicable interest period for term SOFR loans. Term SOFR loans bear interest at term SOFR plus an applicable rate ranging from 175 to 275 basis points per annum, depending on the percentage of the commitments utilized, plus an additional 10 basis points per annum credit spread adjustment. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted term SOFR rate for a one-month interest period plus 100 basis points, plus an applicable margin ranging from 75 to 175 basis points per annum, depending on the percentage of the commitments utilized. Chesapeake also pays a commitment fee on unused commitment amounts under the Credit Facility ranging from 37.5 to 50 basis points per annum, depending on the percentage of the commitments utilized.

The New Credit Facility is subject to customary events of default, remedies, and cure rights for credit facilities of this nature.

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 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 provided for a $200 million sublimit of the aggregate commitments that was available for the issuance of letters of credit. The Exit Credit Facility bore 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 were due to mature three years after the Effective Date and the Tranche B Loans were due to mature four years after the Effective Date. The Company was 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 Credit Agreement was subject to various financial and other covenants and also contained 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. In December 2022, the Tranche A Loans and Tranche B Loans were both repaid and the Exit Credit Facility was terminated.

Borrowings under our credit agreements bore interest at an average interest rate of 8.7% during the 2022 Successor Period. The Company has no additional secured debt outstanding as of December 31, 2022.

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 guaranteed the Exit Credit Facility.

The Notes were issued pursuant to an indenture, dated as of February 5, 2021, among the Issuer, the guarantor party thereto 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 to holders of record on the immediately preceding January 15 and July 15.

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.

The Notes and the Vine Notes are the Company's senior unsecured obligations. Accordingly, they rank (i) equal in right of payment to all existing and future senior unsecured indebtedness, (ii) effectively subordinate in right of payment to all existing and future secured indebtedness, including indebtedness under the New 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 New Credit Facility), (ii) are subordinated to all existing and future secured indebtedness of such guarantor, including such guarantor's guarantee of indebtedness under our New 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.

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 expected to be phased out for most U.S. dollar settings on June 30, 2023, 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 and can be applied prospectively to contract modifications through December 31, 2022. In December 2022, we terminated our only agreement that referenced LIBOR, the Exit Credit Facility, and entered into the New Credit Facility. We no longer have any arrangements that reference LIBOR and the adoption of this guidance did not have a material impact on our consolidated financial statements and related disclosures.

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 natural gas and oil 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.

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 natural gas, oil 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, 2022
2023	$ 565
2024	555
2025	481
2026	442
2027	407
2028-2036	1,832
Total	$ 4,282

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 natural gas and oil 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, 2022 and 2021 are detailed below:

	Successor	
	December 31, 2022	December 31, 2021
Revenues and royalties due others	$ 734	$ 617
Accrued drilling and production costs	253	142
Accrued hedging costs	109	113
Accrued compensation and benefits	72	91
Other accrued taxes	84	86
Operating leases	86	29
Joint interest prepayments received	34	14
Current liabilities held for sale[(a)]	144	—
Other	111	110
Total other current liabilities	$ 1,627	$ 1,202

(a) As of December 31, 2022, certain liabilities associated with the sale of a portion of our Eagle Ford assets have been classified as current liabilities held for sale. See Note 23 for additional information.

9. Leases

We are a lessee under various agreements for drilling rigs, compressors, vehicles, office space and gas treating plants. As of December 31, 2022, 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 right of use ("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.

The following table presents our ROU assets and lease liabilities as of December 31, 2022 and 2021. As of December 31, 2022 and 2021, we did not have any finance leases.

	Successor	
	Operating Leases	
	December 31, 2022	December 31, 2021
ROU assets	$ 119	$ 38
Lease liabilities:		
Current lease liabilities	$ 86	$ 29
Long-term lease liabilities	33	9
Total lease liabilities, net	$ 119	$ 38

As of December 31, 2022, we had operating leases of $73 million related to drilling rig leases, which have been executed but not yet commenced. These operating leases are expected to commence in 2023 with lease terms expiring through 2025.

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

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Lease cost:				
Amortization of ROU assets	$ —	$ —	$ 1	$ 9
Interest on lease liability	—	—	—	1
Finance lease cost	—	—	1	10
Operating lease cost	51	33	3	17
Short-term lease cost	74	13	—	32
Total lease cost	$ 125	$ 46	$ 4	$ 59
Other information:				
Operating cash outflows from finance lease	$ —	$ —	$ —	$ 1
Operating cash outflows from operating leases	$ 15	$ 7	$ —	$ 9
Investing cash outflows from operating leases	$ 110	$ 39	$ 3	$ 40
Financing cash outflows from finance lease	$ —	$ —	$ 1	$ 9

	Successor	
	December 31, 2022	December 31, 2021
Weighted average remaining lease term - operating leases	1.54 years	1.44 years
Weighted average discount rate - operating leases	6.64 %	3.80 %

Maturity analysis of operating lease liabilities are presented below:

	Successor
	December 31, 2022
2023	$ 88
2024	38
2025	—
Total lease payments	126
Less imputed interest	(7)
Present value of lease liabilities	119
Less current maturities	(86)
Present value of lease liabilities, less current maturities	$ 33

10. Revenue

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

	Successor			
	Year Ended December 31, 2022			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 4,041	$ —	$ —	$ 4,041
Haynesville	3,481	—	—	3,481
Eagle Ford	261	1,798	212	2,271
Powder River Basin	20	66	13	99
Natural gas, oil and NGL revenue	$ 7,803	$ 1,864	$ 225	$ 9,892
Marketing revenue	$ 2,455	$ 1,547	$ 229	$ 4,231

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

	Predecessor			
	Period from January 1, 2021 through February 9, 2021			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 119	$ —	$ —	$ 119
Haynesville	53	—	—	53
Eagle Ford	17	159	17	193
Powder River Basin	7	20	6	33
Natural gas, oil and NGL revenue	$ 196	$ 179	$ 23	$ 398
Marketing revenue	$ 78	$ 141	$ 20	$ 239

	Predecessor			
	Year Ended December 31, 2020			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 631	$ —	$ —	$ 631
Haynesville	362	—	—	362
Eagle Ford	129	1,202	97	1,428
Powder River Basin	41	170	20	231
Mid-Continent	25	55	13	93
Natural gas, oil and NGL revenue	$ 1,188	$ 1,427	$ 130	$ 2,745
Marketing revenue from contracts with customers	$ 494	$ 1,195	$ 110	$ 1,799
Other marketing revenue	3	67	—	70
Marketing revenue	$ 497	$ 1,262	$ 110	$ 1,869

Major Customers

For the 2022 Successor Period, sales to Shell Energy North America and Valero Energy Corporation accounted for approximately 13% and 10%, respectively, of total revenues (before the effects of hedging). 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 and 2020 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% and 17%, respectively, of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2022 Successor Period, 2021 Successor Period, 2021 Predecessor Period or 2020 Predecessor Period.

Accounts Receivable

Accounts receivable as of December 31, 2022 and 2021 are detailed below:

	Successor	
	December 31, 2022	December 31, 2021
Natural gas, oil and NGL sales	$ 1,171	$ 922
Joint interest	246	158
Other	24	38
Allowance for doubtful accounts	(3)	(3)
Total accounts receivable, net	$ 1,438	$ 1,115

11. Income Taxes

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

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Current				
Federal	$ 37	$ —	$ —	$ (3)
State	10	—	—	(6)
Current Income Taxes	47	—	—	(9)
Deferred				
Federal	(1,112)	(45)	(54)	—
State	(220)	(4)	(3)	(10)
Deferred Income Taxes	(1,332)	(49)	(57)	(10)
Total	$ (1,285)	$ (49)	$ (57)	$ (19)

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	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Income tax expense (benefit) at the federal statutory rate of 21%	$ 767	$ 188	$ 1,119	$ (2,051)
State income taxes (net of federal income tax benefit)	75	(86)	238	(41)
Change in valuation allowance due to Acquisitions	19	(49)	—	—
Change in valuation allowance excluding impact of Acquisitions	(2,147)	(179)	(1,191)	2,010
Reorganization items	—	60	(173)	41
Transaction costs	2	11	—	—
Removal of stranded tax effects in accumulated other comprehensive income	—	—	(57)	—
Other	(1)	6	7	22
Total	$ (1,285)	$ (49)	$ (57)	$ (19)

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. Our state income tax provision can fluctuate as a result of changing state apportionment factors and state tax rates. The 2021 Successor Period resulted in a state tax benefit before valuation allowance. The shift of our state profile towards a higher overall state tax rate as a consequence of the Vine Acquisition caused an increase to our state deferred tax assets. Such increase was offset in full by an increase to our valuation allowance. The Marcellus Acquisition during the 2022 Successor Period resulted in a similar, but lessened effect.

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	
	December 31, 2022	December 31, 2021
Deferred tax liabilities:		
Property, plant and equipment	$ (253)	$ —
Other	(5)	(3)
Deferred tax liabilities	(258)	(3)
Deferred tax assets:		
Property, plant and equipment	—	340
Net operating loss carryforwards	870	784
Carrying value of debt	29	31
Excess business interest expense carryforward	665	684
Asset retirement obligations	91	86
Investments	11	66
Accrued liabilities	21	38
Derivative instruments	137	289
Other	130	68
Deferred tax assets	1,954	2,386
Valuation allowance	(345)	(2,383)
Deferred tax assets after valuation allowance	1,609	3
Net deferred tax asset	$ 1,351	$ —

As of December 31, 2022, and 2021, we had deferred tax assets of $1.954 billion and $2.386 billion, respectively, upon which we had a valuation allowance of $345 million and $2.383 billion, respectively. Of the net change in the valuation allowance of $2.038 billion, $1.351 billion was attributable to the valuation allowance release during the fourth quarter of 2022 and $687 million was associated primarily with pre-tax income for the year.

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.

For the years ended December 31, 2021 and 2020, we maintained a full valuation allowance against our deferred tax assets based upon the conclusion that it was more likely than not that the deferred tax assets would not be realized. An item of negative evidence consisted of the cumulative pre-tax book losses over rolling three-year periods, primarily due to recurring operational losses and $8.446 billion of impairments of proved natural gas and oil properties recorded in the quarter ended March 31, 2020 (see Note 19). For the cumulative three-year period ended December 31, 2022, we are in a cumulative loss position, but given the magnitude of the 2020 losses rolling off relative to the 2021 and 2022 positive pre-tax book income, we anticipate a return to cumulative pre-tax income during 2023. The expectation of future earnings along with reversals of existing taxable timing differences provide us with sufficient positive evidence to conclude that $1.351 billion of our federal and state deferred tax assets are more likely than not to be realized. Accordingly, we have released the valuation allowance for this amount during 2022. We continue to maintain a partial valuation allowance of $345 million against the portion of our federal and state deferred tax assets such as NOLs, credit carryovers, and capital losses, which may expire before we are able to utilize those due to the application of the limitations under Section 382 and the ordering in which such attributes may be applied.

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. 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 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 include a portion of our tax depreciation, depletion, and amortization deductions along with a portion of our realized hedging losses. We incurred sufficient recognized built-in losses during the 2021 tax year such that we have 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 was $5 billion, all of which reduced our NOL carryforwards. As a result of the Section 382 limitation, $307 million of federal NOLs remaining after the CODI reduction were estimated to expire before they would become utilizable and, as such, were removed from our deferred tax assets. The states we operate in generally have similar rules for attribute reduction and Section 382 limitation which resulted 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. In the 2021 Successor Period, we recorded a $49 million net deferred tax liability determined through business combination accounting. Upon the completion of Vine’s tax returns in the 2022 Successor Period, the net deferred tax liability was adjusted to $30 million. As a result of this adjustment to the deferred tax liability, we increased our valuation allowance and recorded $19 million of income tax expense in the 2022 Successor Period. Additionally, we acquired NOL and interest expense carryforwards which 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 $12 million per year resulting in approximately $14 million per year of available utilization in those years.

The Marcellus Acquisition during the 2022 Successor Period was treated as a taxable asset acquisition with no tax carryovers acquired.

As of December 31, 2022, we have an income tax receivable of $168 million included in other current assets within our consolidated balance sheets.

As of December 31, 2022, 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	$ 814	$ 24	$ —
Indefinitely lived	2,265	102	—
Total federal net operating losses	$ 3,079	$ 126	$ —
Excess business interest expense (indefinitely lived)	$ 1,435	$ 90	$ 1,368

We had state NOL carryforwards of approximately $3.901 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.

On August 16, 2022, the President of the United States signed into law the Inflation Reduction Act of 2022 ("IRA") which, among other things, includes provisions for a 15% corporate alternative minimum tax on book income for companies whose average book income exceeds $1 billion for any three consecutive years preceding the tax year and a 1% excise tax on stock buybacks. These changes are generally in effect for tax years beginning after December 31, 2022. Based on our book income in the past three years, we do not believe we will be subject to the corporate alternative minimum tax in 2023. However, we may become subject to the corporate alternative minimum tax in future years. It is our policy that we view the alternative minimum tax as an excess tax over regular income tax and therefore, our deferred tax assets will continue to be assessed for realizability on the basis of whether they reduce a regular tax liability. Should we pay alternative minimum tax in the future and thus acquire credit carryovers related thereto, such deferred tax assets on these will be separately evaluated for valuation allowance purposes.

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 December 31, 2022, and 2021, the amount of unrecognized tax benefits related to NOL carryforwards, tax credit carryforwards, and tax liabilities associated with uncertain tax positions was $69 million and $74 million, respectively. As of December 31, 2022, $29 million is related to state tax receivables not expected to be recovered, $4 million is related to tax credit carryforwards, and the remainder is related to NOL carryforwards. As of December 31, 2021, $29 million is related to state tax receivables not expected to be recovered and the remainder is related to NOL carryforwards. If recognized, $33 million of the uncertain tax positions identified would have an effect on the effective tax rate. As of December 31, 2022, and 2021, 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 considered this information and determined that we had 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 12 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	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Unrecognized tax benefits at beginning of period	$ 74	$ 74	$ 74	$ 74
Additions based on tax positions related to the current year	2	—	—	—
Additions to tax positions of prior years	2	—	—	—
Settlements	—	—	—	—
Expiration of the applicable statute of limitations	—	—	—	—
Reductions to tax positions of prior years	(9)	—	—	—
Unrecognized tax benefits at end of period	$ 69	$ 74	$ 74	$ 74

Our federal and state income tax returns are subject to examination by federal and state tax authorities. Our tax years 2019 through 2022 remain open for all purposes of examination by the IRS as do the WildHorse short period return for January 1, 2019, through February 1, 2019, the Vine 2019 and 2020 federal income tax returns and the Vine short period return for January 1, 2021 through November 1, 2021. However, certain earlier tax years remain open for adjustment to the extent of their NOL carryforwards available for future utilization.

In addition, tax years 2019 through 2022 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 2,092,918 shares of New Common Stock were reserved for future distributions under the Plan. During the 2022 and 2021 Successor Periods, 439,370 and 864,090 reserved shares, respectively, were issued to resolve allowed General Unsecured Claims.

On November 1, 2021, we completed the Vine Acquisition and issued 18,709,399 shares of New Common Stock. On March 9, 2022, we completed the Marcellus Acquisition and issued 9,442,185 shares of New Common Stock. See further discussion of both acquisitions in Note 4.

Dividends

In May 2021, we initiated a new annual dividend on our shares of common stock, expected to be paid quarterly. We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. The following table summarizes our dividend payments in the 2022 and 2021 Successor Periods:

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 2021		$ 119	
Payment Date	**Stockholders of Record Date**	**Dividend Payment**	**Rate Per Share**
March 22, 2022	March 7, 2022	$ 210	$ 1.7675
June 2, 2022	May 19, 2022	298	$ 2.34
September 1, 2022	August 17, 2022	280	$ 2.32
December 1, 2022	November 15, 2022	424	$ 3.16
Total dividends paid 2022		$ 1,212	

On February 21, 2023, we declared a quarterly dividend payable of $1.29 per share, which will be paid on March 23, 2023 to stockholders of record at the close of business on March 7, 2023. The dividend consists of a base quarterly dividend in the amount of $0.55 per share and a variable quarterly dividend in the amount of $0.74 per share.

Share Repurchase Program

As of December 2, 2021, the Company was authorized to purchase up to $1.0 billion of the Company's common stock and/or warrants under a share repurchase program. In June 2022, our Board of Directors authorized an expansion of the share repurchase program by $1.0 billion, bringing the total authorized share repurchase amount to $2.0 billion for stock and/or warrants. The share repurchase program will expire on December 31, 2023.

In March 2022, we commenced our share repurchase program and throughout the 2022 Successor Period, we repurchased 11.7 million shares of common stock for an aggregate price of $1.1 billion. The shares of common stock that were repurchased during the 2022 Successor Period were retired and recorded as a reduction to common stock and retained earnings.

Warrants

	Class A Warrants	Class B Warrants	Class C Warrants[a]
Outstanding as of February 10, 2021	11,111,111	12,345,679	9,768,527
Converted into New Common Stock	(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
Converted into New Common Stock[b]	(1,609,641)	(29,679)	(959,247)
Converted in warrant exchange offer[b]	(4,752,207)	(7,879,030)	(7,252,004)
Issued for General Unsecured Claims	—	—	829,109
Outstanding as of December 31, 2022	4,495,004	4,404,564	4,006,229

(a) As of December 31, 2022, we had 1,489,337 of reserved Class C Warrants.

(b) During the 2022 Successor Period, we issued 18,408,228 common shares as a result of Warrant exercises, inclusive of the shares issued as part of the Warrant exchange offers described below.

As discussed in Note 2, on the Effective Date, we issued Class A, Class B and Class C Warrants that were 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 1, 2022, and the adjusted exercise prices are $24.32, $28.28, and $31.84 per share for the Class A, Class B and Class C Warrants, respectively. Additionally, we have recalculated the number of shares of New Common Stock issuable upon the exercise of each of the Class A, Class B and Class C Warrants, respectively, and as a result, 1.12 shares are issuable upon the exercise of a Class A, Class B or Class C Warrant.

On August 18, 2022, we announced exchange offers relating to our outstanding Class A Warrants, Class B Warrants and Class C Warrants. The exchange offers expired on October 7, 2022 and resulted in the issuance of 16,305,984 shares of our New Common Stock in exchange for the cancellation of (i) 4,752,207 Class A Warrants, (ii) 7,879,030 Class B Warrants and (iii) 7,252,004 Class C Warrants. Under the exchange offers, the Warrants were exchanged in a cashless transaction and were converted to shares of our New Common Stock at a ratio of 0.8636 for Class A Warrants, 0.8224 for Class B Warrants and 0.7890 for Class C Warrants, respectively. As the fair value of the New Common Stock issued was greater than the fair value of the Warrants tendered in the exchange offers due to stated exchange premiums, we recorded a non-cash deemed dividend of $67 million. Such fair values were determined using our stock price that is considered a Level 1 input.

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

During 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 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 ("RSUs"), 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 2022 and 2021 Successor Periods, we granted RSUs to employees and non-employee directors under the LTIP, which will vest over a three-year to five-year period and one-year period, respectively. The fair value of RSUs 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 RSUs 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
Granted	666	$	81.87
Vested	(300)	$	48.11
Forfeited	(184)	$	56.54
Unvested as of December 31, 2022	957	$	68.91

(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 2022 and 2021 Successor Periods was approximately and $26 million and $25 million based on the stock price at the time of vesting, respectively.

As of December 31, 2022, there was approximately $50 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 2.71 years.

Performance Share Units. In the 2022 and 2021 Successor Periods, 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 total shareholder return ("TSR") and relative TSR ("rTSR"), and could result in a total payout between 0% - 200% of the target units. For the PSUs granted in 2021, the performance criteria also include share price hurdles which could result in a total payout between 0% - 100% 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 tables present the assumptions used in the valuation of the PSUs granted in the 2022 and 2021 Successor Periods.

2022 PSU Awards

Assumption	**TSR, rTSR**
Risk-free interest rate	2.00 %
Volatility	70.2 %

2021 PSU Awards

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

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
Granted	133	$ 109.65
Vested	—	$ —
Forfeited	(40)	$ 57.48
Unvested as of December 31, 2022	276	$ 88.28

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, 2022, there was approximately $16 million of total unrecognized compensation expense related to unvested PSUs. The expense is expected to be recognized over a weighted average period of approximately 1.99 years.

Predecessor Share-Based Compensation

Our Predecessor share-based compensation program consisted of restricted stock, stock options and PSUs 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 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

The aggregate intrinsic value of restricted stock units that vested during the 2020 Predecessor Period was approximately $1 million based on the stock price at the time of vesting.

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	$ —

(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 RSUs, stock options, and PSUs for the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
General and administrative expenses	$ 19	$ 7	$ 3	$ 20
Natural gas and oil properties	4	2	—	1
Production expense	3	2	—	1
Total RSU, stock option and PSU compensation	$ 26	$ 11	$ 3	$ 22
Related income tax benefit	$ 6	$ —	$ —	$ —

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%. In addition to our employer match contributions, in 2022 we commenced a discretionary fixed dollar contribution benefit for all employees, paid quarterly, which is based upon a calculation of 1% of Adjusted Free Cash Flow less the base quarterly dividend. This discretionary fixed dollar contribution is subject to an annual maximum contribution of $15,000 per employee. We contributed $22 million, $8 million, $2 million and $24 million to the 401(k) Plan in the 2022 Successor Period, 2021 Successor Period, 2021 Predecessor Period and 2020 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 natural gas and oil 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 natural gas and oil derivative instruments were designated for hedge accounting as of December 31, 2022 and 2021.

As of December 31, 2022, we reclassified $65 million of derivative liabilities (notional volume of 9.6 bcf of natural gas and notional volume of 4.8 mmbbls of oil) to liabilities held for sale, as these open hedge positions will be novated to WildFire Energy I LLC upon completion of the sale of a portion of our Eagle Ford assets. See Note 23 for more details.

Natural Gas and Oil Derivatives

As of December 31, 2022 and 2021, our natural gas and oil 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 natural gas and oil derivative instrument assets (liabilities) as of December 31, 2022 and 2021 are provided below:

	Successor			
	December 31, 2022		December 31, 2021	
	Notional Volume	Fair Value	Notional Volume	Fair Value
Natural gas (Bcf):				
Fixed-price swaps	382	$ (494)	637	$ (675)
Collars	721	49	205	(82)
Three-way collars	4	(2)	—	—
Call options	18	(22)	18	(17)
Basis protection swaps	652	(32)	252	(11)
Total natural gas	1,777	(501)	1,112	(785)
Oil (MMBbls):				
Fixed-price swaps	1	(32)	13	(356)
Collars	2	7	—	—
Basis protection swaps	6	1	9	(2)
Total oil	9	(24)	22	(358)
Total estimated fair value		$ (525)		$ (1,143)

In prior periods we had terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months were 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, 2022 and 2021 on a gross basis and after same-counterparty netting:

	Gross Fair Value[(a)]	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheets
Successor			
As of December 31, 2022			
Commodity Contracts:			
Short-term derivative asset	$ 200	$ (166)	$ 34
Long-term derivative asset	87	(40)	47
Short-term derivative liability	(598)	166	(432)
Long-term derivative liability	(214)	40	(174)
Total derivatives	$ (525)	$ —	$ (525)
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)

(a) These financial assets (liabilities) are measured at fair value on a recurring basis utilizing significant other observable inputs; see further discussion on fair value measurements below.

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 natural gas, oil and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes, and, as such, are classified as Level 2. These values are compared to the values given by our counterparties for reasonableness. 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.

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, 2022, our natural gas and oil derivative instruments were spread among 12 counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that were also lenders (or affiliates of lenders) under our New Credit Facility. The contracts entered into with these counterparties are secured by the same collateral that secures the 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, 2022, we did not have any cash or letters of credit posted as collateral for our commodity derivatives.

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:

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

(a) These losses were included as a component of total natural gas and oil derivatives.

Our accumulated other comprehensive loss balance 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. We did not have any changes or items impacting other comprehensive income for the 2022 Successor Period or the 2021 Successor Period.

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	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Balance, beginning of period	$ 14	$ —	$ —	$ 7
Additions pending the determination of proved reserves	1	24	—	—
Divestitures and other	—	—	—	—
Reclassifications to proved properties	—	(10)	—	—
Charges to exploration expense	(5)	—	—	(7)
Balance, end of period[(a)]	$ 10	$ 14	$ —	$ —

(a) Our capitalized exploratory well costs balance as of December 31, 2022, consisted of one project for which we had suspended exploratory well costs capitalized for a period greater than one year. As of December 31, 2022, we are currently evaluating the project.

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

17. Other Property and Equipment

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

	Successor		Estimated Useful Life
	December 31, 2022	December 31, 2021	(in years)
Buildings and improvements	$ 325	$ 330	10 - 39
Computer equipment	92	87	5
Land	32	37	
Sand mine[(a)]	—	2	10 - 30
Other	51	39	5 - 20
Total other property and equipment, at cost	500	495	
Less: accumulated depreciation	(58)	(26)	
Total other property and equipment, net	$ 442	$ 469	

(a) These assets were transferred to assets held for sale as of December 31, 2022.

18. Investments

Momentum Sustainable Ventures LLC. During the fourth quarter of 2022, Chesapeake entered into an agreement with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture and sequestration project, which will gather natural gas produced in the Haynesville Shale for re-delivery to Gulf Coast markets, including LNG export. The pipeline is expected to have an initial capacity of 1.7 Bcf/d expandable to 2.2 Bcf/d. The carbon capture portion of the project anticipates capturing and permanently sequestering up to 2.0 million tons per annum of CO2. The natural gas gathering pipeline in-service is projected for the fourth quarter of 2024, and the carbon sequestration portion of the project is subject to regulatory approvals. We have a 35% interest in the project and have committed approximately $330 million to the project through the end of 2024. We have accounted for this investment as an equity method investment and its carrying value as of December 31, 2022 was $18 million.

FTS International, Inc. (FTSI). 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 closed during 2022.

19. Impairments

Impairments of Natural Gas and Oil Properties

During the 2020 Predecessor Period we recognized $8.446 billion of impairments related to our natural gas and oil properties. In 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 natural gas and oil properties, and our sand mine assets.

Proved Gas and Oil Properties

Our impairment test involved a Step 1 assessment to determine if the net book value of our proved natural gas and oil properties was 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 represented a Level 1 input.

Certain natural gas and oil 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

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.

During the 2022 Successor Period, 2021 Successor Period and 2021 Predecessor Period, we did not have any material impairments of our natural gas and oil properties or fixed assets.

20. Exploration Expense

During the 2022 Successor Period, exploration expense charges of $23 million were primarily the result of non-cash impairment charges in unproved properties of $8 million, $6 million of charges related to dry hole expense and $6 million of geological and geophysical expense. We did not have material exploration expenses during the 2021 Successor Period or 2021 Predecessor Period. The exploration expense charges of $427 million during the 2020 Predecessor Period were primarily the result of non-cash impairment charges in unproved properties of $411 million, primarily in our Eagle Ford, Haynesville, Powder River Basin and Mid-Continent operating areas.

Unproved natural gas and oil 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.

21. Other Operating Expense (Income), Net

In the 2022 Successor Period, we recognized approximately $41 million of costs related to our Marcellus Acquisition, which included integration costs, consulting fees, financial advisory fees, legal fees and change in control expense in accordance with Chief's existing employment agreements.

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.

22. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below:

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Asset retirement obligations, beginning of period	$ 360	$ 241	$ 144
Additions[(a)]	53	48	—
Revisions[(b)]	16	63	—
Settlements and disposals[(c)]	(54)	(3)	(1)
Held for sale[(d)]	(57)	—	—
Accretion expense	17	11	1
Impact of fresh start accounting	—	—	97
Asset retirement obligations, end of period	335	360	241
Less current portion	12	11	5
Asset retirement obligations, long-term	$ 323	$ 349	$ 236

(a) During the 2022 Successor Period, approximately $27 million of additions relate to the Marcellus Acquisition. During the 2021 Successor Period, approximately $44 million of additions relate to the Vine Acquisition. 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 2022 Successor Period, approximately $47 million of disposals related to our Powder River Basin assets. See Note 4 for further discussion of these transactions.

(d) As of December 31, 2022, approximately $57 million of asset retirement obligations associated with the sale of a portion of our Eagle Ford assets have been reclassified as other current liabilities held for sale.

23. Subsequent Events

In January 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for approximately $1.425 billion. This transaction, which is subject to certain customary closing conditions, including certain regulatory approvals, is expected to close in the first quarter of 2023. As of December 31, 2022, we ceased depreciation on the assets associated with the sale and classified approximately $811 million of property and equipment, net and $8 million of other assets as held for sale included within current assets held for sale on the consolidated balance sheets. Additionally, approximately $65 million of derivative liabilities, $57 million of asset retirement obligations liabilities and $22 million of other liabilities were classified as held for sale and included within other current liabilities on the consolidated balance sheets as of December 31, 2022.

In February 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Energy for approximately $1.4 billion. This transaction, which is subject to certain customary closing conditions, including certain regulatory approvals, is expected to close in the second quarter of 2023.

Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities (unaudited)

Certain reserves and production information was previously disclosed in a per barrel of oil equivalent. As the majority of our production profile consists of natural gas, we have converted this information, including prior periods, from a per barrel of oil equivalent, to a per one thousand cubic feet of natural gas equivalent, referred to, on such a converted basis, as per Mcfe.

Net Capitalized Costs

Capitalized costs related to our natural gas, oil and NGL producing activities are summarized as follows:

	Successor	
	December 31, 2022	December 31, 2021
Natural gas and oil properties:		
Proved	$ 11,096	$ 7,682
Unproved	2,022	1,530
Total	13,118	9,212
Less accumulated depreciation, depletion and amortization	(2,373)	(882)
Net capitalized costs	$ 10,745	$ 8,330

Unproved properties as of December 31, 2022 and 2021, consisted mainly of leasehold acquired through our Vine Acquisition and Marcellus Acquisition. 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 Natural Gas and Oil Property Acquisition, Exploration and Development

Costs incurred in natural gas and oil property acquisition, exploration and development, including capitalized interest and asset retirement costs, are summarized as follows:

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Acquisition of properties[(a)]:				
Proved properties	$ 2,321	$ 2,183	$ —	$ 3
Unproved properties	795	1,121	—	6
Exploratory costs	15	31	—	8
Development costs	1,918	717	58	887
Costs incurred	$ 5,049	$ 4,052	$ 58	$ 904

(a) Includes $2.31 billion and $0.79 billion of proved and unproved property acquisitions, respectively, related to our Marcellus Acquisition in 2022. Includes $2.18 billion and $1.10 billion of proved and unproved property acquisitions, respectively, related to our Vine Acquisition in 2021.

Results of Operations from Natural Gas, Oil and NGL Producing Activities

The following table includes revenues and expenses associated directly with our natural gas, oil and NGL producing activities for the periods presented. It does not include any derivative activity, interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas, oil and NGL operations.

	Successor		Predecessor	
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021	Year Ended December 31, 2020
Natural gas, oil and NGL sales	$ 9,892	$ 4,401	$ 398	$ 2,745
Production expenses	(475)	(297)	(32)	(373)
Gathering, processing and transportation expenses	(1,059)	(780)	(102)	(1,082)
Severance and ad valorem taxes	(242)	(158)	(18)	(149)
Exploration	(23)	(7)	(2)	(427)
Depletion and depreciation	(1,703)	(882)	(64)	(1,014)
Accretion of asset retirement obligations	(17)	(11)	(1)	(12)
Impairment of natural gas and oil properties	—	—	—	(8,446)
Imputed income tax provision[(a)]	(1,440)	(535)	(42)	1,988
Results of operations from natural gas, oil and NGL producing activities	$ 4,933	$ 1,731	$ 137	$ (6,770)

(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).

Natural Gas, Oil and NGL Reserve Quantities

Our petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2022, 2021 and 2020. Independent petroleum engineering firm Netherland, Sewell & Associates, Inc. estimated an aggregate of 92% of our estimated proved reserves (by volume) as of December 31, 2022.

Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil 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 natural gas or oil 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.

The information provided below on our natural gas, oil 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 proved reserves for the periods presented:

	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
December 31, 2022				
Proved reserves, beginning of period (Successor)	7,824	209.7	82.0	9,573
Extensions, discoveries and other additions	60	2.1	1.5	82
Revisions of previous estimates	1,989	22.5	5.0	2,155
Production	(1,308)	(19.4)	(6.0)	(1,461)
Sale of reserves-in-place	(122)	(16.5)	(8.6)	(273)
Purchase of reserves-in-place	2,926	—	—	2,926
Proved reserves, end of period (Successor)	11,369	198.4	73.9	13,002
Proved developed reserves:				
Beginning of period (Successor)	4,246	165.7	61.7	5,610
End of period (Successor)	7,385	157.2	58.9	8,681
Proved undeveloped reserves:				
Beginning of period (Successor)	3,578	44.0	20.3	3,963
End of period[(a)] (Successor)	3,984	41.2	15.0	4,321

	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
December 31, 2021				
Proved reserves, beginning of period (Predecessor)	3,530	161.3	52.0	4,809
Extensions, discoveries and other additions	1,744	41.0	16.9	2,091
Revisions of previous estimates	1,522	33.3	21.1	1,848
Production	(807)	(25.9)	(8.0)	(1,010)
Sale of reserves-in-place	—	—	—	—
Purchase of reserves-in-place	1,835	—	—	1,835
Proved reserves, end of period (Successor)	7,824	209.7	82.0	9,573
Proved developed reserves:				
Beginning of period (Predecessor)	3,196	158.1	51.4	4,452
End of period (Successor)	4,246	165.7	61.7	5,610
Proved undeveloped reserves:				
Beginning of period (Predecessor)	334	3.2	0.6	357
End of period[(a)] (Successor)	3,578	44.0	20.3	3,963
December 31, 2020				
Proved reserves, beginning of period (Predecessor)	6,566	358.0	120.0	9,434
Extensions, discoveries and other additions	100	1.1	0.4	109
Revisions of previous estimates	(2,326)	(148.2)	(50.6)	(3,519)
Production	(684)	(37.3)	(11.3)	(976)
Sale of reserves-in-place	(126)	(12.3)	(6.5)	(239)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period (Predecessor)	3,530	161.3	52.0	4,809
Proved developed reserves:				
Beginning of period (Predecessor)	3,377	201.4	82.1	5,078
End of period (Predecessor)	3,196	158.1	51.4	4,452
Proved undeveloped reserves:				
Beginning of period (Predecessor)	3,189	156.6	37.9	4,356
End of period[(a)] (Predecessor)	334	3.2	0.6	357

(a) As of December 31, 2022, 2021 and 2020, there were no PUDs that had remained undeveloped for five years or more.

During 2022, we acquired 2,926 bcfe primarily related to the Marcellus Acquisition. We recorded extensions and discoveries of 82 bcfe primarily related to new PUDs and previously unproved producing wells in emerging plays. We recorded 2,155 bcfe of upward revisions of previous estimates, which consisted of 866 bcfe of revisions to PUDs primarily due to development plan optimization through prioritizing longer laterals and multi-well pad development in the Haynesville, 1,156 bcfe of revisions to existing or new proved developed properties primarily due to performance and 133 bcfe of revisions due to higher natural gas, oil and NGL prices in 2022. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2022, were $6.36 per mcf, $93.67 per bbl and $43.58 per bbl, respectively, before basis differential adjustments.

During 2021, we acquired 1,835 bcfe primarily related to the Vine Acquisition. We recorded extensions and discoveries of 2,091 bcfe 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 1,848 bcfe of upward revisions of previous estimates, which consisted of 1,284 bcfe due to lateral length adjustments, performance and updates to our five-year development plan and 564 bcfe due to higher natural gas, oil and NGL prices in 2021. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2021, were $3.60 per mcf, $66.56 per bbl and $35.81 per bbl, respectively, before basis differential adjustments.

During 2020, we recorded extensions and discoveries of 109 bcfe primarily in the Marcellus and Haynesville primarily related to successfully drilled new well additions. We sold 239 bcfe of proved reserves for approximately $136 million primarily in the Mid-Continent. We recorded 3,519 bcfe of downward revisions of previous estimates consisting of 2,538 bcfe 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 1,248 bcfe due to lower natural gas, oil and NGL prices in 2020, and upward revisions of 267 bcfe due to ongoing portfolio evaluation including performance adjustments. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2020, were $1.98 per mcf, $39.57 per bbl and $17.32 per bbl, 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, 2022, 2021 and 2020 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 natural gas, oil 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 natural gas, oil and NGL reserves based on the standardized measure:

	Years Ended December 31,		
	2022	2021	2020
Future cash inflows	$ 76,626 (a)	$ 33,700 (b)	$ 8,247 (c)
Future production costs	(10,177)	(6,735)	(2,963)
Future development costs	(5,343) (d)	(3,687) (e)	(563) (f)
Future income tax provisions	(10,440)	(2,254)	(9)
Future net cash flows	50,666	21,024	4,712
Less effect of a 10% discount factor	(24,361)	(8,737)	(1,626)
Standardized measure of discounted future net cash flows	$ 26,305	$ 12,287	$ 3,086

(a) Calculated using prices of $6.36 per mcf of natural gas, $93.67 per bbl of oil and $43.58 per bbl of NGL, before basis differential adjustments.

(b) Calculated using prices of $3.60 per mcf of natural gas, $66.56 per bbl of oil and $35.81 per bbl of NGL, before basis differential adjustments.

(c) Calculated using prices of $1.98 per mcf of natural gas, $39.57 per bbl of oil and $17.32 per bbl of NGL, before basis differential adjustments.

(d) Included approximately $979 million of future plugging and abandonment costs as of December 31, 2022.

(e) Included approximately $846 million of future plugging and abandonment costs as of December 31, 2021.

(f) Included approximately $429 million of future plugging and abandonment costs as of December 31, 2020.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2022	2021	2020
Standardized measure, beginning of period[a]	$ 12,287	$ 3,086	$ 9,000
Sales of natural gas and oil produced, net of production costs and gathering processing and transportation[b]	(8,116)	(3,414)	(1,140)
Net changes in prices and production costs	14,256	6,674	(5,576)
Extensions and discoveries, net of production and development costs	251	2,834	71
Changes in estimated future development costs	(1,512)	(459)	1,933
Previously estimated development costs incurred during the period	690	130	665
Revisions of previous quantity estimates	6,697	2,034	(1,839)
Purchase of reserves-in-place	7,047	2,807	—
Sales of reserves-in-place	(402)	—	(112)
Accretion of discount	1,371	309	902
Net change in income taxes	(4,972)	(1,423)	14
Changes in production rates and other	(1,292)	(291)	(832)
Standardized measure, end of period[a]	$ 26,305	$ 12,287	$ 3,086

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excludes gains and losses on derivatives. Production costs includes severance and ad valorem taxes.

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, 2022 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, 2022 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, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022 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 22, 2023

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 no later than 120 days following the fiscal year ended December 31, 2022 (the “2023 Proxy Statement”).

Item 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2023 Proxy Statement.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information called for by this Item 12 is incorporated herein by reference to the 2023 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 2023 Proxy Statement.

Item 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2023 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	8/11/2021	
2.3	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.	10-K	001-13726	10.36	2/24/2022	
2.4	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.	10-K	001-13726	10.37	2/24/2022	
2.5	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.	10-K	001-13726	10.38	2/24/2022	
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	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
10.4	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
10.5	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
10.6	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
10.7	Form of Indemnity Agreement.	8-K	001-13726	10.6	2/9/2021
10.8†	Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.7	2/9/2021
10.9	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
10.10	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
10.11	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
10.12	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
10.13†	Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	4/27/2021

10.14†	Form of Incentive Agreement between Executive Vice President / Senior Vice President and Chesapeake Energy Corporation.	10-K/A	001-13726	10.14	4/30/2021
10.15†	Form of Executive/Employee Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.	10-K	001-13726	10.18	2/24/2022
10.16†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.	10-Q	001-13726	10.9	5/13/2021
10.17†	Form of Performance Share Unit Award (Absolute TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.10	8/10/2021
10.18†	Form of Performance Share Unit Award (Relative TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.11	8/10/2021
10.19†	Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.1	10/12/2021
10.20†	Form of Participation Agreement pursuant to Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.2	10/12/2021
10.21†	Executive Chairman Agreement by and between Michael Wichterich and Chesapeake Energy Corporation, dated October 11, 2021	8-K	001-13726	10.4	10/12/2021
10.22†	Second Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	10/12/2021
10.23	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	11/2/2021
10.24	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	11/2/2021
10.25	Registration Rights Agreement dated March 9, 2022, by and among the Company and The Jan & Trevor Rees-Jones Revocable Trust, Rees-Jones Family Holdings, LP, Chief E&D Participants, LP, and Chief E&D (GP) LLC.	8-K	001-13726	10.1	3/9/2022
10.26	Registration Rights Agreement dated March 9, 2022, by and among the Company and Radler 2000 Limited Partnership.	8-K	001-13726	10.2	3/9/2022
10.27	Form of Dealer Manager Agreement in connection with exchange offers for Warrants.	S-4	333-266961	10.34	8/18/2022
10.28	Form of Tender and Support Agreement, dated September 12, 2022, in connection with exchange offers for Warrant.	S-4/A	333-266961	10.35	9/12/2022

10.29	Credit Agreement, dated as of December 9, 2022, among Chesapeake Energy Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and other parties thereto.	8-K	001-13726	10.1	12/12/2022	
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 Netherland, Sewell & Associates, Inc.					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 Netherland, Sewell & Associates, Inc.					X
101 INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.					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 (formatted as Inline XBRL and contained in Exhibit 101).					X

* 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 22, 2023

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 22, 2023
/s/ MOHIT SINGH **Mohit Singh**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2023
/s/ GREGORY M. LARSON **Gregory M. Larson**	Vice President - Accounting & Controller (Principal Accounting Officer)	February 22, 2023
/s/ MICHAEL WICHTERICH **Michael Wichterich**	Chairman of the Board	February 22, 2023
/s/ TIMOTHY S. DUNCAN **Timothy S. Duncan**	Director	February 22, 2023
/s/ BENJAMIN C. DUSTER, IV **Benjamin C. Duster, IV**	Director	February 22, 2023
/s/ SARAH A. EMERSON **Sarah A. Emerson**	Director	February 22, 2023
/s/ MATTHEW M. GALLAGHER **Matthew M. Gallagher**	Director	February 22, 2023
/s/ BRIAN STECK **Brian Steck**	Director	February 22, 2023

CHESAPEAKE ENERGY CORPORATION

an Oklahoma Corporation

SIGNIFICANT SUBSIDIARIES*

Limited Liability Companies	State of Organization
Chesapeake Exploration, L.L.C.	Oklahoma
Chesapeake Appalachia, L.L.C.	Oklahoma
Chesapeake Energy Marketing, L.L.C.	Oklahoma
Brazos Valley Longhorn, L.L.C.	Delaware
Vine Oil & Gas Parent GP LLC	Delaware
Brix Oil & Gas Holdings GP LLC	Delaware
Cypress Exploration & Development LLC	Texas

Partnerships	State of Organization
Chesapeake Louisiana, L.P.	Oklahoma

* In accordance with Regulation S-K Item 601(b)(21), the names of particular subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (as that term is defined in Rule 1-02(w) of Regulation S-X) as of the end of the year covered by this report have been omitted.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-256214, 333-260833 and 333-263820) and Form S-8 (Nos. 333-253340 and 333-260834) of Chesapeake Energy Corporation (Successor) of our report dated February 22, 2023 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 22, 2023

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-256214, 333-260833 and 333-263820) and Form S-8 (Nos. 333-253340 and 333-260834) of Chesapeake Energy Corporation (Predecessor) of our report dated February 24, 2022 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 22, 2023

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Annual Report on Form 10-K of Chesapeake Energy Corporation for the year ended December 31, 2022 (the "Annual Report") of our report dated February 9, 2023, with respect to estimates of reserves and future net revenue to the Chesapeake Energy Corporation interest, as of December 31, 2022, and to all references to our firm included in the Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Eric J. Stevens

Eric J. Stevens, P.E.

President and Chief Operating Officer

Dallas, Texas
February 22, 2023

CERTIFICATION

I, Domenic J. Dell'Osso, Jr., certify that:

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

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

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

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

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

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

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

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

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

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

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

February 22, 2023

By: /s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
President and Chief Executive Officer

CERTIFICATION

I, Mohit Singh, certify that:

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

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

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

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

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

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

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

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

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

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

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

February 22, 2023

By: /s/ MOHIT SINGH
Mohit Singh
Executive Vice President and Chief Financial Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Domenic J. Dell'Osso, Jr., President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 22, 2023

By: /s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mohit Singh, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 22, 2023

By: /s/ MOHIT SINGH
Mohit Singh
Executive Vice President and Chief Financial Officer

Exhibit 95.1

Mine Safety Disclosures

Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and Item 104 of Regulation S-K (17 CFR 229.104) require certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977 (as amended by the Mine Improvement and New Emergency Response Act of 2006, the "Mine Act").

Burleson Sand LLC ("Burleson Sand") is a wholly owned subsidiary of Brazos Valley Longhorn, L.L.C. (successor in interest to WildHorse Resource Development Corporation) ("WildHorse"), which is a wholly owned subsidiary of Chesapeake Energy Corporation. On January 4, 2018, Burleson Sand acquired surface and sand rights on approximately 727 acres in Burleson County, Texas to construct and operate an in-field sand mine to support WildHorse's exploration and development operations. Burleson Sand began operations in September 2018 and is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Mine Act. The MSHA inspects mining facilities on a regular basis and issues citations and orders when it believes a violation has occurred under the Mine Act.

The MSHA, upon determination that a violation of the Mine Act has occurred, may issue a citation or an order which generally proposes civil penalties or fines upon the mine operator. Citations and orders may be appealed with the potential of reduced or dismissed penalties.

The table below reflects citations, orders, violations and proposed assessments issued to Burleson Sand by MSHA during the three-month period ended December 31, 2022. Due to timing and other factors, the data may not agree with the mine data retrieval systems maintained by MSHA at www.MSHA.gov.

	Burleson Sand Mine 41-05369
Section 104 significant and substantial citations	—
Section 104(b) orders	—
Section 104(d) citations and orders	—
Section 110(b)(2) violations	—
Section 107(a) orders	—
Total dollar value of MSHA assessments proposed	$ —
Total number of mining related fatalities	—
Received notice of pattern of violations under section 104(e)	No
Received notice of potential to have pattern under section 104(e)	No
Legal actions pending as of last day of period	—
Legal actions initiated during period	—
Legal actions resolved during period	None

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 9, 2023

Mr. Nick Penner
Chesapeake Energy Corporation
6100 North Western Avenue
Oklahoma City, OK 73118

Dear Mr. Penner:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2022, to the Chesapeake Energy Corporation (Chesapeake) interest in certain oil and gas properties located in the United States. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 92.2 percent of all proved reserves owned by Chesapeake. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Chesapeake's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Chesapeake interest in these properties, as of December 31, 2022, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Gas (MMCF)	NGL (MBBL)	Oil (MBBL)	Total	Present Worth at 10%
Proved Developed Producing	6,926,825.9	54,022.7	150,055.6	41,738,653.7	22,074,507.1
Proved Undeveloped	3,830,669.2	0.0	0.0	15,199,196.0	8,816,181.6
Total Proved	10,757,495.1	54,022.7	150,055.6	56,937,849.7	30,890,688.8

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, proved developed non-producing, probable, and possible reserves that may exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

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

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2022. For gas volumes, the average Henry Hub spot price of $6.36 per MMBTU is adjusted for energy content, transportation fees, gathering fees, treating fees, and market differentials; for certain properties, gas prices are negative after adjustments. For the Eagle Ford – South Texas properties, the fees associated with Chesapeake's Minimum Volume Commitment contracts are not included; at contract expiration, fees for gathering and treating, at current contract rates, are included in the gas price adjustments. For oil and NGL volumes, the average NYMEX West Texas Intermediate spot price of $93.67 per barrel is adjusted for quality, transportation fees, and market differentials. The average adjusted product prices weighted by production over the remaining lives of the properties are $5.022 per MCF of gas, $36.45 per barrel of NGL, and $92.72 per barrel of oil.

Operating costs used in this report are based on operating expense records of Chesapeake, the operator of the properties. As requested, operating costs are limited to direct lease- and field-level costs and Chesapeake's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

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

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Chesapeake interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Chesapeake receiving its net revenue interest share of estimated future gross production.

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

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

The data used in our estimates were obtained from Chesapeake, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. James D. Berry, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2014 and has over 6 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

By: /s/ James D. Berry, P.E.
James D. Berry, P.E. 128972
Vice President

Date Signed: February 9, 2023

By: /s/ William J. Knights, P.G.
William J. Knights, P.G. 1532
Vice President

Date Signed: February 9, 2023

JDB:RKL

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

(iv) Provide improved recovery systems.

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

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

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

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

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

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

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

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

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

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

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

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

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

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

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

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

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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

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

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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

(20) *Production costs*.

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

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

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

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

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

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

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

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

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

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

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

> e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
>
> f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

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

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

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

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

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

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

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
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> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

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

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