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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2021

OR

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

For the transition period from _________ to _________

Commission File Number 001-19514

Gulfport Energy Corporation
(Exact Name of Registrant As Specified in Its Charter)

Delaware	**86-3684669**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
3001 Quail Springs Parkway	
Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	(Zip Code)

(405) 252-4600
(Registrant 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, $0.0001 par value per share	GPOR	The New York Stock Exchange

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 (Section 232.405 of this chapter) during the preceding 12 months (or 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 definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐
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 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 Exchange Act). Yes ☐ No ☒

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2021 was approximately $ 703.9 million. As of February 25, 2022, there were 21,477,000 shares of our $0.0001 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2022 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

GULFPORT ENERGY CORPORATION
TABLE OF CONTENTS

DEFINITIONS

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

2019 Plan. 2019 Amended and Restated Stock Incentive Plan.

2020 Plan. 2020 Incentive Plan, which provides incentive awards for select employees of the Company that were tied to the achievement of one or more performance goals relating to certain financial and operational metrics over a period of time.

2023 Notes. 6.625% Senior Notes due 2023.

2024 Notes. 6.000% Senior Notes due 2024.

2025 Notes. 6.375% Senior Notes due 2025.

2026 Notes. 6.375% Senior Notes due 2026.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. Chapter 11 of Title 11 of the United States Code.

Bankruptcy Court. The United States Bankruptcy Court for the Southern District of Texas.

Bankruptcy Rules. The Federal Rules of Bankruptcy Procedure.

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

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent.

Btu. British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

Building Loan. Loan agreement for our corporate headquarters scheduled to mature in June 2025.

Chapter 11 Cases. Voluntary petitions filed on November 13, 2020 by Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

CODI. Cancellation of indebtedness income.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas, oil and NGL.

Combined Period. Combined Successor Period and Predecessor Period.

DD&A. Depreciation, depletion and amortization.

Debtors. Collectively, Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

Developed Acreage. The number of acres allocated or assignable to productive wells or wells capable of production.

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

DIP Credit Facility. Senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million.

Dry Hole. A well that does not produce crude oil and/or natural gas in economically producible quantities.

Exploratory Well. A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

Emergence Date. May 17, 2021.

Exit Credit Agreement. The Second Amended and Restated Credit Agreement with the Bank of Nova Scotia as lead administrative agent and various lender parties providing for the Exit Facility and the First-Out Term Loan.

Exit Credit Facility. Collectively, the First-Out Term Loan and the Exit Facility, with an initial borrowing base and elected commitment amount of up to $580 million.

Exit Facility. Senior secured reserve-based revolving credit facility with The Bank of Nova Scotia as the lead arranger and administrative agent and various lender parties.

First-Out Term Loan. Senior secured term loan in an aggregate maximum principal amount of $180 million.

GAAP. Accounting principles generally accepted in the United States of America.

Grizzly. Grizzly Oil Sands ULC.

Grizzly Holdings. Grizzly Holdings Inc.

Gross Acres or Gross Wells. Refers to the total acres or wells in which a working interest is owned.

Guarantors. All existing consolidated subsidiaries that guarantee the Company's revolving credit facility or certain other debt.

Held By Production. Refers to an oil and gas lease continued into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

Horizontal Drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

Indentures. Collectively, the 1145 Indenture and the 4(a)(2) Indenture governing the Successor Senior Notes.

IRC. The Internal Revenue Code of 1986, as amended.

LIBOR. London Interbank Offered Rate.

LOE. Lease operating expenses.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent.

Natural Gas Liquids (NGL). Hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

Net Acres or Net Wells. Refers to the sum of the fractional working interests owned in gross acres or gross wells.

Net Revenue Interest (NRI). An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production.

New Common Stock. $0.0001 par value common stock issued by the Successor on the Emergence Date.

New Credit Facility. The Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and various lender parties, providing for a new money senior secured reserve-based revolving credit facility effective as of October 14, 2021.

New Preferred Stock. $0.0001 par value preferred stock issued by the Successor on the Emergence Date.

NYMEX. New York Mercantile Exchange.

OCC. Oklahoma Corporation Commission.

Petition Date. November 13, 2020.

Plan. The Amended Joint Chapter 11 Plan of Reorganization of Gulfport Energy Corporation and Its Debtor Subsidiaries.

Predecessor Period. Period from January 1, 2021 through May 17, 2021.

Predecessor Senior Notes. Collectively, the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes.

Pre-Petition Revolving Credit Facility. Senior secured revolving credit facility, as amended, with The Bank of Nova Scotia as the lead arranger and administrative agent and certain lenders from time-to-time party thereto with a maximum facility amount of $580 million.

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

Proved Developed Reserves (PDPs). Reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. 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.

Proved Undeveloped Reserves (PUDs). Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. 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. Undrilled locations can be classified as having proved 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.

PV-10. Present net value of estimated future net revenues, discounted at 10%.

Repurchase Program. A stock repurchase program to acquire up to $100 million of Gulfport's outstanding New Common Stock. It is authorized to extend through December 31, 2022, and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.

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

Royalty Interest. Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

RSA. Restructuring Support Agreement.

SCOOP. Refers to the South Central Oklahoma Oil Province, a term used to describe a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. Our acreage is primarily in Garvin, Grady and Stephens Counties.

SEC. The United States Securities and Exchange Commission.

Section 382. Internal Revenue Code Section 382.

Standardized Measure. Standardized measure of discounted future net cash flows.

Successor Period. Period from May 18, 2021 through December 31, 2021.

Successor Senior Notes. 8.000% Senior Notes due 2026.

Tcfe. One trillion cubic feet of natural gas equivalent.

Undeveloped Acreage. Lease or mineral acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

USEPA. United States Environmental Protection Agency.

Utica. Refers to the Utica Play that includes the hydrocarbon bearing rock formations commonly referred to as the Utica formation located in the Appalachian Basin of the United States and Canada. Our acreage is located primarily in Belmont, Harrison, Jefferson and Monroe Counties in Eastern Ohio.

Working Interest (WI). 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. Refers to West Texas Intermediate.

FORWARD-LOOKING STATEMENTS

This Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward looking statements by terms such as “may,” “will,” “should,” “could,” “would,” “expects,” “plans,” “anticipates,” “intends,” “believes,” “estimates,” “projects,” “predicts,” “potential” and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as the expected impact of the novel coronavirus disease (COVID-19) pandemic on our business, our industry and the global economy, estimated future production and net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), the impact of our emergence from bankruptcy, share repurchases, business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in Item 1A. “*Risk Factors*” and Item 7. “*Management's Discussion and Analysis of Financial Condition and Results of Operations*” sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

Investors should note that we announce financial information in SEC filings. We may use the Investors section of our website (www.gulfportenergy.com) to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on our website is not part of this Annual Report on Form 10-K.

SUMMARY RISK FACTORS

Financial, Liquidity and Commodity Price Risks

- Natural gas, oil and NGL prices fluctuate widely, and lower prices for extended time periods are likely to have a material adverse effect on our business.
- 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.
- Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.
- Our debt and other financial commitments may limit our financial and operating flexibility.
- Our development, acquisition and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.
- Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.
- A change of control could limit our use of net operating losses to reduce future taxable income.

Industry, Business and Operational Risks

- The oil and gas development, exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.
- If we are not able to replace reserves, we may not be able to sustain production.
- The actual quantities of and future net revenues from our proved reserves may be less than our estimates.
- Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.
- Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.
- Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
- Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.
- Multi-well pad drilling may result in volatility in our operating results and delay the conversion of our PUD reserves.
- We are not the operator of all our oil and natural gas properties and therefore are not positioned to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.
- Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. 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.
- Substantially all of our producing properties are located in Eastern Ohio and Oklahoma, making us vulnerable to risks associated with operating in only these regions.
- The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.
- The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.
- 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.
- We are required to pay fees to some of our midstream service providers based on minimum volumes regardless of actual volume throughput.

- The outbreak of the novel coronavirus, or COVID-19, has affected and may materially adversely affect, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our operations, financial performance and condition, operating results and cash flows.
- A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.
- Terrorist activities could materially and adversely affect our business and results of operations.
- Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.
- We may engage in acquisition and divestiture activities that involve substantial risks.

Legal and Regulatory Risks

- We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.
- Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.
- Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.
- Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

Risks Associated with our Emergence from Bankruptcy

- We recently emerged from bankruptcy, which may adversely affect our business and relationships.
- Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information because of the implementation of the Plan and the transactions contemplated thereby.
- Upon emergence from bankruptcy, the composition of our board of directors changed significantly.

Risks Associated with an Investment in Us

- The market price of our securities is subject to volatility.
- Future sales or the availability for sale of substantial amounts of our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and could impair our ability to raise capital through future sales of equity securities.
- Certain of our stockholders own a significant portion of our outstanding debt and equity securities, and their interests may not always coincide with the interests of other holders of the New Common Stock.
- There may be future dilution of our common stock, which could adversely affect the market price of our common stock.
- Our amended and restated certificate of incorporation provides, subject to certain exceptions, that the Court of Chancery of the State of Delaware will be the sole and exclusive forum for certain stockholder litigation matters, which could limit our stockholders’ ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

PART I

ITEM 1. BUSINESS

Our Business

Gulfport is an independent natural gas-weighted exploration and production company with assets primarily located in the Appalachia and Anadarko basins. Our principal properties are located in Eastern Ohio, where we target development in what is commonly referred to as the Utica formation, and Central Oklahoma where we target development in the SCOOP Woodford and Springer formations. Gulfport's predecessor was incorporated in the State of Delaware in July 1997. Our corporate headquarters are located in Oklahoma City, Oklahoma and shares of Gulfport's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "GPOR". Our corporate strategy is focused on the economic development of our asset base in an effort to generate sustainable free cash flow.

As of December 31, 2021, we had 3.9 Tcfe of proved reserves with a Standardized Measure of $4.1 billion and a PV-10 of $4.3 billion. See "*Definitions*" above for our definition of PV-10 (a non-GAAP financial measure) and "*Oil, Natural Gas and NGL Reserves*" below for a reconciliation of our standardized measure of discounted future net cash flows (the most directly comparable GAAP measure) to PV-10.

Information About Us

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished 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 our recent news releases. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Emergence From Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On November 13, 2020, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases were administered jointly under the caption *In re Gulfport Energy Corporation, et al.,* Case No. 20-35562 (DRJ). The Bankruptcy Court confirmed the Plan and entered the confirmation order on April 28, 2021, and the Debtors emerged from the Chapter 11 Cases on the Emergence Date. On May 18, 2021, we began trading on the NYSE under the symbol "GPOR".

Although we are no longer a debtor-in-possession, we operated as debtors-in-possession through the pendency of the Chapter 11 Cases. See Note 2 and Note 3 of our consolidated financial statements for a complete discussion of the Chapter 11 Cases.

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. As a result of the Chapter 11 Cases, we reduced our total indebtedness by $1.4 billion by issuing equity in a reorganized entity to the holders of our unsecured notes and allowed general unsecured claimants. In addition, Gulfport reassessed its organizational needs post emergence and significantly reduced its general and administrative expense to ensure its cost structure is competitive with industry peers. We continue to focus on optimizing development of our resource plays, reducing our operating costs, per well drilling costs, general and administrative costs, and managing our liquidity. We believe our plan to generate free cash flow on an annual basis will allow us to further strengthen our balance sheet and return capital to shareholders.

Business Strategy

Gulfport aims to create sustainable value through the economic development of our significant resource plays in the Utica and SCOOP operating areas. Our strategy is to develop our assets in an environmentally responsible manner, while generating sustainable cash flow, improving margins and operating efficiencies and returning capital to shareholders. To accomplish these goals, we allocate capital expenditures to projects we believe offer the highest rate of return and we deploy leading drilling and completion techniques and technologies in our development efforts.

2022 Outlook

Our 2022 capital expenditure program is expected to be in a range of $340 million to $380 million. We plan to operate on average approximately one operated rig in each of our Utica and SCOOP development areas. In the Utica, we intend to spud 15 gross (13.4 net) operated horizontal wells, complete drilling on 24 gross (21.7 net) operated horizontal wells and commence sales on 17 gross (15.6 net) horizontal wells. In the SCOOP, we intend to spud five gross (3.6 net) operated horizontal wells, complete drilling on 8 gross (5.5 net) operated horizontal wells and commence sales on 13 gross (10.3 net) operated horizontal wells. We expect to fund these expenditures with our operating cash flow and borrowings under our revolving credit agreement.

We expect this drilling program to result in approximately 975 to 1,025 MMcfe per day of production in 2022.

Additionally, in 2022, we expect to focus on our strategy of returning capital to our shareholders. In the fourth quarter of 2021, our board of directors authorized the repurchase of up to $100 million of our outstanding common stock and we paid our first cash dividend payment on our New Preferred Stock.

Operating Areas

Utica - The Utica covers hydrocarbon bearing rock formations located in the Appalachian Basin of the United States and Canada. We have approximately 187,000 net reservoir acres located primarily in Belmont, Harrison, Jefferson and Monroe Counties in Eastern Ohio where the Utica ranges in thickness from 600 to over 750 feet. During the Combined Period, we produced approximately 772 MMcfe per day net to our interests in this area and it accounts for approximately 77% of our total production.

SCOOP - The SCOOP is a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. We have approximately 74,000 net reservoir acres (comprised of approximately 41,000 in the Woodford formation and approximately 33,000 in the Springer formation) located primarily in Garvin, Grady and Stephens Counties. The Woodford Shale across our position ranges in thickness from 200 to over 400 feet and directly overlies the Hunton Limestone and underlies the Sycamore formation, both of which are also locally productive reservoirs. The Sycamore formation consists of hydrocarbon-bearing interbedded shales and siliceous limestones ranging in thickness from 150 to over 450 feet and is overlain by the Caney Shale. The Springer formation across our position is comprised of a series of lenticular sand and shale units. The primary targets are a series of porous, low clay and organic-rich packages within the Goddard Shale member ranging in thickness from 50 to over 250 feet. During the Combined Period, we produced approximately 231 MMcfe per day net to our interests in this area and it accounts for approximately 23% of our total production.

Oil, Natural Gas and NGL Reserves

Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the reserve estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A. "*Risk Factors*" contained elsewhere in this Form 10-K.

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

	December 31, 2021			
	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Total (Bcfe)
Utica				
Proved developed	2	1,482	9	1,550
Proved undeveloped	4	1,073	4	1,123
Total proved	7	2,555	13	2,673
SCOOP				
Proved developed	6	445	22	613
Proved undeveloped	4	477	18	610
Total proved	10	921	40	1,223
Total				
Proved developed[(1)]	8	1,928	31	2,165
Proved undeveloped	8	1,550	22	1,733
Total proved	16	3,478	54	3,898

Totals may not sum or recalculate due to rounding.

(1) Includes approximately 2 Bcfe of net reserves located in non-core operating districts.

	Successor		
	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(1)]	$ 4,649	$ 3,585	$ 8,234
Present value of estimated future net revenue (PV-10)[(1)]	$ 2,655	$ 1,660	$ 4,316
Standardized measure[(1)]			$ 4,138

Totals may not sum due to rounding.

(1) 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 prices and costs under existing economic conditions as of December 31, 2021, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2021. The prices used in our PV-10 measure were $66.55 per barrel and $3.60 per MMBtu, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2021. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense of $178 million as of December 31, 2021.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 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 reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

Proved Reserves

Estimates of proved reserves and related information are presented in accordance with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules permit the use of reliable technologies to estimate and categorize reserves and require the use of the unweighted average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the prior 12 months (unless contractual arrangements designate the price) to calculate economic producibility of reserves and the discounted cash flows reported as the Standardized Measure of Future Net Cash Flows Relating to Proved Reserves. Refer to Note 20 of our consolidated financial statements for more information pertaining to our proved reserves and the preparation of such estimates.

The following table summarizes the changes in our estimated proved reserves during 2021 (in Bcfe):

Proved Reserves, December 31, 2020 (Predecessor)	2,588
Sales of oil and natural gas reserves in place	—
Extensions and discoveries	695
Revisions of prior reserve estimates	982
Current production	(366)
Proved Reserves, December 31, 2021 (Successor)	3,898

Total may not sum due to rounding.

Sales of oil and natural gas reserves in place. These are reductions to proved reserves resulting from the divestiture of minerals in place during a period. During 2021, we sold approximately 0.2 Bcfe of proved oil and natural gas reserves through various sales of our non-operated interests in our other non-core assets.

Extensions and discoveries. These are additions to our proved reserves that result from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery. Extensions of approximately 694.6 Bcfe of proved reserves were primarily attributable to the continued development of our Utica and SCOOP acreage. We added 29 PUD locations in our Utica acreage for 352.2 Bcfe and 34 PUD locations in our SCOOP acreage for 342.2 Bcfe. The five-year development plan focused on generating sustainable cash flow limited our ability to add significant well locations.

Revisions of prior reserve estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from development plan changes, new information normally obtained from development drilling and production history or a change in economic factors, such as commodity prices, operating costs or development costs.

We experienced total upward revisions of 982.2 Bcfe in estimated proved reserves, of which 889.2 Bcfe was the result of commodity price changes. Commodity prices experienced volatility throughout 2021 and the 12-month average price for natural gas increased from $1.99 per MMBtu for 2020 to $3.60 per MMBtu for 2021, the 12-month average price for NGL increased from $15.40 per barrel for 2020 to $31.90 per barrel for 2021, and the 12-month average price for crude oil increased from $39.54 per barrel for 2020 to $66.55 per barrel for 2021.

Upward revisions of 157.6 Bcfe were a result of a combination of well performance, operating and development cost improvements and working interest changes. A small downward revision of 64.6 Bcfe was also experienced as a result of the exclusion of 4 PUD locations in our Utica field when changes in our schedule moved development of these PUD locations beyond five years of initial booking. The development plan change reflects our commitment to capital discipline and funding future activities within cash flow and ongoing optimization of our development plan.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves at December 31, 2021, 2020 and 2019 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information*,* in Note 20 of our consolidated financial statements.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2021, our proved undeveloped reserves totaled 1,550 Bcf of natural gas, 8 MMBbl of oil and 22 MMBbl of NGL, for a total of 1,733 Bcfe. Approximately 65% and 35% of our PUD reserves at year-end 2021 were located in Utica and SCOOP, respectively. PUDs will be converted from undeveloped to developed as the applicable wells commence production or there are no material incremental completion capital expenditures associated with such proved developed reserves.

We record PUD reserves only after a development plan has been approved by our senior management and board of directors to complete the associated development drilling within five years from the time of initial booking. The PUD locations identified in our development plan are determined based on an analysis of the information that we have available at that time. After a development plan has been adopted, we may periodically make adjustments to the approved development plan due to events and circumstances that have occurred subsequent to the time the plan was approved. These circumstances may include changes in commodity price outlook and costs, delays in the availability of infrastructure, well permitting delays and new data from recently completed wells.

The following table summarizes the changes in our estimated proved undeveloped reserves during 2021 (in Bcfe):

Proved Undeveloped Reserves, December 31, 2020 (Predecessor)	1,061
Extensions and discoveries	694
Conversion to proved developed reserves	(362)
Revisions of prior reserve estimates	341
Proved Undeveloped Reserves, December 31, 2021 (Successor)	1,733

Total may not sum due to rounding.

Extensions and discoveries. Our extensions of approximately 694.4 Bcfe were primarily attributed to the addition of 29 PUD drilling locations in the Utica field and 34 PUD drilling locations in the SCOOP field as a result of our current five-year development plan that is focused on generating sustainable cash flow.

Conversion to proved developed reserves. Our 2021 development activities resulted in the conversion of approximately 362.4 Bcfe into proved developed producing reserves, attributable to 12 PUD locations in the Utica field and 11 PUD locations in the SCOOP field. These 23 PUDs represent a conversion rate of 28% for 2021.

Revision of prior reserve estimates. We experienced total upward revisions of 340.8 Bcfe in estimated proved undeveloped reserves, of which 340.8 Bcfe was the result of improved commodity prices. The 12-month average price for natural gas increased from $1.99 per MMBtu for 2020 to $3.60 per MMBtu for 2021, the 12-month average price for NGL increased from $15.40 per barrel for 2020 to $31.90 per barrel for 2021, and the 12-month average price for crude oil increased from $39.54 per barrel for 2020 to $66.55 per barrel for 2021.

We also experienced 67.6 Bcfe of downward revisions as a result of the exclusion of 4 PUD locations in our Utica field when changes in our schedule moved development of these PUD locations beyond five years of initial booking. These downward revisions were offset by upward revisions of 67.6 Bcfe in estimated proved reserves from a combination of working interest changes, well development design updates and operating and development cost improvements.

Costs incurred relating to the development of PUDs were approximately $268.1 million in 2021.

All PUD drilling locations included in our 2021 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2021, 0.01% of our total proved reserves were classified as proved developed non-producing.

Reserves Estimation

Reserve estimates for the years ended December 31, 2021, 2020 and 2019 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") for all of our operating areas.

NSAI is an independent petroleum engineering firm. A copy of the summary reserve reports is included as Exhibit 99.1 to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI for our properties such as ownership interest, oil and gas production, well test data, commodity prices, operating and development costs and other considerations, including availability and costs of infrastructure and status of permits. Our Senior Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 20 years of reservoir and operations experience. In addition, our geoscience staff has approximately 85 years combined industry experience and our reservoir staff has approximately 75 years combined experience.

Internal Controls Over Proved Reserve Estimates

Our proved reserve estimates are prepared in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production, operating, marketing and capital data, which data is based on actual production as reported by us;
- verification of property ownership by our land department;
- preparation of year-end reserve estimates by NSAI in coordination with our experienced reservoir engineers;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- provision of quarterly updates to our board of directors regarding operational data, including production, drilling and completion activity levels and any significant changes in our reserves;
- annual review by our board of directors of our year-end reserve report and year-over-year changes in our proved reserves, as well as any changes to our previously adopted development plans;
- annual review and approval by our senior management and our board of directors of a multi-year development plan;
- annual review by our senior management of adjustments to our previously adopted development plan and considerations involved in making such adjustments; and
- annual review by our board of directors of changes in our previously approved development plan made by senior management and technical staff during the year, including the substitution, removal or deferral of PUD locations.

PV-10 Sensitivities

As noted above, our December 31, 2021 proved reserves were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2021 of $66.55 per barrel and $3.60 per MMBtu. Holding production and development costs constant, if SEC pricing were $73.21 per barrel and $3.96 per MMBtu, or a 10% increase, this would have resulted in an increase of 16.2 Bcfe of our total proved reserves and a $787 million increase in PV-10 value at December 31, 2021. Holding production and development costs constant, if SEC pricing were $59.90 per barrel and $3.24 per MMBtu, or a 10% decrease, this would have resulted in a decrease of 23.8 Bcfe of our total proved reserves and a $787 million decrease in PV-10 value at December 31, 2021. For each of these scenarios, the 139 PUDs that were economic at SEC pricing were included.

Acreage

The following table presents our total gross and net developed and undeveloped acres as of December 31, 2021:

Field	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Utica	127,590	101,979	91,033	85,330
SCOOP	49,104	34,934	7,959	5,673
Other	1,021	395	4,377	1,253
Total	177,715	137,308	103,369	92,256

Of our leases that are not held by production, most have a five-year primary term, many of which include options to extend the primary term. We manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our operations to establish production in paying quantities in order to hold leases prior to the expiration dates, paying the prescribed lease extension payments, planning non-core divestitures or strategic acreage trades with other operators to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The following table sets forth the potential expiration periods of gross and net undeveloped leasehold acres as of December 31, 2021:

	Undeveloped Acres	
	Gross Acres	Net Acres
Years Ending December 31:		
2022	15,960	14,494
2023	13,937	13,045
2024	261	253
After 2024	2,637	2,565
Held by production or operations	70,342	61,667
Total[(1)]	103,137	92,024

(1) Does not include acreage not subject to expiration.

Productive Wells

The following table presents our total gross and net productive wells, expressed separately for oil and gas, as of December 31, 2021:

Field	Average NRI/WI Percentages	Productive Oil Wells		Productive Gas Wells		Total Wells	
		Gross	Net	Gross	Net	Gross	Net
Utica	48.75/59.71	147	42.8	514	352.0	661	394.7
SCOOP	23.17/28.80	105	16.7	516	161.8	621	178.6
Other	Various	20	1.3	8	0.1	28	1.4
Total[(1)]		331	60.8	1,141	513.9	1,472	574.7

(1) We also have override/royalty interests in 162 wells with an average NRI of 0.5%, which are not material to our operations. Totals may not sum due to rounding.

Drilling Activity

The following table sets forth information with respect to operated wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	29	26.6	26	24.4	25	22.4
Dry	—	—	—	—	—	—
Total	29	26.6	26	24.4	25	22.4
Exploratory:						
Productive	—	—	—	—	1	0.8
Dry	—	—	—	—	—	—
Total	—	—	—	—	1	0.8

The following table presents activity by operating area for the year ended December 31, 2021:

	Operated				Non-Operated			
	Drilled		Turned to Sales		Drilled		Turned to Sales	
Field	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica[(1)]	20	18.9	17	17.0	—	—	—	—
SCOOP[(2)]	9	7.7	11	9.4	25	1.77	21	0.05
Total	29	26.6	28	26.4	25	1.77	21	0.05

(1) Of the 20 gross wells drilled in 2021, 10 were completed as producing wells, nine were in various stages of drilling and one was waiting on completion as of December 31, 2021.
(2) Of the nine gross wells drilled in 2021, four were in various stages of drilling and five were in various stages of completion as of December 31, 2021.

Production, Prices and Production Costs

The following table presents our production volumes, average prices received and average production costs during the periods indicated (sales totals in thousands):

	Successor	Predecessor	Non-GAAP Combined	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Natural gas sales					
Natural gas production volumes (MMcf)	208,641	124,279	332,921	344,999	458,178
Natural gas production volumes (MMcf/d)	915	907	912	943	1,255
Total sales	$ 906,096	$ 344,390	$ 1,250,486	$ 671,535	$ 1,135,381
Avg. price without the impact of derivatives ($/Mcf)	$ 4.34	$ 2.77	$ 3.76	$ 1.95	$ 2.48
Impact from settled derivatives ($/Mcf)(1)	$ (1.44)	$ (0.03)	$ (0.91)	$ 0.33	$ 0.23
Avg. price, including settled derivatives ($/Mcf)	$ 2.90	$ 2.74	$ 2.85	$ 2.28	$ 2.71
Oil and condensate sales					
Oil and condensate production volumes (MBbl)	1,167	531	1,699	1,803	2,186
Oil and condensate production volumes (MBbl/d)	5	4	5	5	6
Total sales	$ 81,347	$ 29,106	$ 110,453	$ 62,902	$ 117,937
Avg. price without the impact of derivatives ($/Bbl)	$ 69.71	$ 54.81	$ 65.01	$ 34.88	$ 53.95
Impact from settled derivatives ($/Bbl)	$ (8.33)	$ —	$ (5.72)	$ 25.76	$ 1.86
Avg. price, including settled derivatives ($/Bbl)	$ 61.38	$ 54.81	$ 59.29	$ 60.64	$ 55.81
NGL sales					
NGL production volumes (MBbl)	2,658	1,211	3,869	3,964	5,074
NGL production volumes (MBbl/d)	12	9	11	11	14
Total sales	$ 105,141	$ 36,780	$ 141,921	$ 66,814	$ 101,448
Avg. price without the impact of derivatives ($/Bbl)	$ 39.56	$ 30.37	$ 36.68	$ 16.86	$ 19.99
Impact from settled derivatives ($/Bbl)(2)	$ (4.88)	$ —	$ (3.35)	$ (0.04)	$ 2.79
Avg. price, including settled derivatives ($/Bbl)	$ 34.68	$ 30.37	$ 33.33	$ 16.82	$ 22.78
Natural gas, oil and condensate and NGL sales					
Natural gas equivalents (MMcfe)	231,594	134,735	366,329	379,600	501,742
Natural gas equivalents (MMcfe/d)	1,016	983	1,004	1,037	1,375
Total sales	$ 1,092,584	$ 410,276	$ 1,502,860	$ 801,251	$ 1,354,766
Avg. price without the impact of derivatives ($/Mcfe)	$ 4.72	$ 3.05	$ 4.10	$ 2.11	$ 2.70
Impact from settled derivatives ($/Mcfe)	$ (1.39)	$ (0.02)	$ (0.89)	$ 0.42	$ 0.24
Avg. price, including settled derivatives ($/Mcfe)	$ 3.33	$ 3.03	$ 3.21	$ 2.53	$ 2.94
Production Costs:					
Avg. lease operating expenses ($/Mcfe)	$ 0.14	$ 0.14	$ 0.14	$ 0.14	$ 0.15
Avg. taxes other than income ($/Mcfe)	$ 0.13	$ 0.09	$ 0.12	$ 0.08	$ 0.08
Avg. transportation, gathering, processing and compression ($/Mcfe)	$ 0.92	$ 1.20	$ 1.02	$ 1.20	$ 1.01
Total LOE, midstream costs and taxes ($/Mcfe)	$ 1.19	$ 1.43	$ 1.28	$ 1.42	$ 1.24

(1) In November 2020, the Company early terminated certain gas sold call options which resulted in a cash payment of $60.2 million.
(2) In April 2020, the Company early terminated certain oil fixed price swaps which resulted in a cash receipt of $40.5 million.

The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2021:

	Successor	Predecessor	Non-GAAP Combined	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Utica					
Net production					
Natural gas (MMcf)	166,906	106,968	273,874	291,133	387,473
Oil (MBbl)	220	183	403	393	247
NGL (MBbl)	562	361	924	1,077	1,812
Total (MMcfe)	171,598	110,235	281,833	299,955	399,828
Avg. price without the impact of derivatives:					
Natural gas ($/Mcf)	$ 4.33	$ 2.64	$ 3.67	$ 1.97	$ 2.28
Oil ($/Bbl)	$ 66.94	$ 52.43	$ 60.35	$ 33.41	$ 51.11
NGL ($/Bbl)	$ 47.16	$ 37.21	$ 43.27	$ 18.55	$ 19.74
Production costs:					
Avg. lease operating expenses ($/Mcfe)	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.12
Avg. taxes other than income ($/Mcfe)	$ 0.07	$ 0.06	$ 0.07	$ 0.07	$ 0.07
Avg. transportation, gathering, processing and compression ($/Mcfe)	$ 0.98	$ 1.26	$ 1.09	$ 1.29	$ 1.07
Total LOE, midstream costs and taxes ($/Mcfe)	$ 1.18	$ 1.45	$ 1.29	$ 1.49	$ 1.26
SCOOP					
Net production					
Natural gas (MMcf)	41,724	17,302	59,026	53,853	70,669
Oil (MBbl)	933	344	1,276	1,392	1,610
NGL (MBbl)	2,095	849	2,945	2,886	3,261
Total (MMcfe)	59,893	24,461	84,353	79,519	99,891
Avg. price without the impact of derivatives:					
Natural gas ($/Mcf)	$ 4.40	$ 3.59	$ 4.16	$ 1.83	$ 2.13
Oil ($/Bbl)	$ 70.37	$ 56.05	$ 66.51	$ 35.31	$ 53.32
NGL ($/Bbl)	$ 37.51	$ 27.46	$ 34.61	$ 16.23	$ 20.13
Production costs:					
Avg. lease operating expenses ($/Mcfe)	$ 0.17	$ 0.22	$ 0.19	$ 0.18	$ 0.18
Avg. taxes other than income ($/Mcfe)	$ 0.29	$ 0.20	$ 0.26	$ 0.10	$ 0.14
Avg. transportation, gathering, processing and compression ($/Mcfe)	$ 0.74	$ 0.90	$ 0.78	$ 0.86	$ 0.80
Total LOE, midstream costs and taxes ($/Mcfe)	$ 1.20	$ 1.32	$ 1.23	$ 1.14	$ 1.12

Our Investments

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.5% interest in Grizzly. As of December 31, 2021, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly's operations have been suspended since 2016. Additionally, Grizzly had no proved reserves as of December 31, 2021. We elected to cease funding capital calls in 2019, and we have no obligation to fund any of the projects Grizzly is pursuing. Failure to fund capital calls may lead to continued dilution of our equity ownership interest in Grizzly. Upon emergence from bankruptcy, we determined that we no longer had the ability to exercise significant influence over operating and financial policies of Grizzly. As such, we discontinued equity method of accounting for our investment in Grizzly.

Mammoth Energy. As discussed in Note 15 of our consolidated financial statements, the Company's previously owned shares of the outstanding common stock of Mammoth Energy were used to settle Class 4A claims during 2021. The Company no longer owns any common stock of Mammoth Energy.

Marketing

The principal function of our marketing operations is to provide natural gas, oil and NGL marketing services, including securing and negotiating commodity transactions, gathering, hauling, processing and transportation services, contract administration and nomination services for production from Gulfport-marketed wells. Generally, natural gas and NGL production is sold to purchasers under both spot and term transactions. Oil production is sold under both spot and term transactions with the majority of our sales contracts being shorter term in nature.

We have entered into long-term gathering, processing and transportation contracts with various parties that reserve capacity for fixed, determinable quantities of production over specified periods of time. Some contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including risk mitigation and satisfaction of our firm transportation delivery commitments. These marketing activities often enhance the value of our production by aggregating volumes and allowing improved flexibility in relation to deal structure, size and counterparty exposure whether through intermediary markets or direct end markets. See Note 18 of our consolidated financial statements for further discussion of our commitments.

Major Customers

Our total natural gas, oil and NGL sales, before the effects of hedging, to major customers (purchasers in excess of 10% of total natural gas, oil and NGL sales) for the Successor Period, Predecessor Period, and years ended December 31, 2020 and 2019 were as follows:

	% of Sales
Period from May 18, 2021 through December 31, 2021 (Successor)	
ECO-Energy	20 %
Macquarie	10 %
Period from January 1, 2021 through May 17, 2021 (Predecessor)	
ECO-Energy	14 %
Macquarie	12 %
Citadel	11 %
Year Ended December 31, 2020 (Predecessor)	
ECO-Energy	12 %
Year Ended December 31, 2019 (Predecessor)	
Morgan Stanley Capital	14 %

Competition

The oil and natural gas industry is intensely competitive, and we compete with many other companies that have greater resources than we have. Competition can negatively impact our ability to successfully source quality vendors and service providers, to secure optimal pipeline access and end markets in which to sell our production, to acquire new properties, and our search for, and the development of, reserves. Many of our competitors not only explore for and produce oil and natural gas, but also have midstream and further downstream operations and market a variety of hydrocarbon products on a regional, national or worldwide basis. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include renewable sources such as wind or solar energy in addition to coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonality

Gulfport drills and completes wells throughout the year, but adverse weather conditions can impact drilling, completion, and field operations, which can impact overall production volumes. Seasonal anomalies can minimize or exaggerate the impact on these operations, while extreme weather events can materially constrain our operations for short periods of time.

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a preliminary review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to certain imperfections in title, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

Regulation - Environment, Health and Safety

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

Shortly after taking office in January 2021, President Biden issued a series of executive orders designed to address climate change and requiring agencies to review environmental actions taken by the Trump administration, as well as a memorandum to departments and agencies to refrain from proposing or issuing rules until a departmental or agency head appointed or designated by the Biden administration has reviewed and approved the rule. These executive orders in part led to the US again depositing an instrument of acceptance of the Paris Agreement, created in 2015 during the United Nations ("U.N.") Climate Change Conference, which thereafter re-entered into force for the US on February 19, 2021. The Paris Agreement requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years beginning in 2020. The terms of the Paris Agreement and the executive orders are expected to result in additional regulations or changes to existing regulations, which could have a material adverse effect on our business. In addition, incentives to conserve energy or use alternative energy sources could have a negative impact on our business. The executive orders and international accord may result in the development of additional regulations or changes to existing regulations. Failure to comply with laws and regulations can lead to the imposition of remedial liabilities, fines, or criminal penalties or to 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 costs of environmental protection and of safety and health compliance to be necessary, manageable parts of our business. 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 policy and regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment, safety and health have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See the Risk Factors described in Item 1A. of this report for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the compulsory pooling or integration of tracts to facilitate exploration and development. Other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations often impose additional operational costs to us and can also limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

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 reduce the amount of natural gas, oil and NGL that we are ultimately able to produce in commercial quantities from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the Bureau of Land Management (BLM) or Bureau of Indian Affairs (BIA) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, on January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. To the extent that the review results in the development of additional restrictions on drilling, limitations on the availability of leases, or restrictions on the ability to obtain required permits, it 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.

Operating Hazards and Insurance

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

We maintain a control of well insurance policy with a $25 million single well limit and a $35 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 $51 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $10 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.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities in response to federal and state requirements. The plans go through a technical review every five years and are updated as necessary. As required by applicable regulations, our facilities are built with secondary containment systems to capture potential releases. We also own additional spill kits with oil booms and absorbent pads that are readily available, if needed. In addition, we have emergency response companies on retainer. These companies specialize in the clean-up of hydrocarbons as a result of spills, blow-outs and natural disasters, and are on call to us 24 hours a day, seven days a week when their services are needed. We pay these companies a retainer plus additional amounts when they provide us with clean up services. Our aggregate payments for the retainer and clean-up services during each of 2021 and 2020 were immaterial. While these companies have been able to meet our service needs when required from time to time in the past, it is possible that the ability of one or more of them to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the areas in which we operate and the nature of our production, we believe other companies would be available to us in the event our primary remediation companies are unable to perform.

Human Capital Management

Employees

As of December 31, 2021, we had 212 employees, a reduction from 256 employees the previous year. The reduction was due to the rightsizing of our organization through a controlled hiring program and a small reduction in workforce in August of 2021. All of our employees are non-bargaining. Attraction and retention of people remains one of the highest strategic goals of the organization. We remain focused on the retention and development of existing employees, as their continued commitment is critical to our success.

During 2021, we continued to adapt to the changing nature of the COVID-19 pandemic, by regularly assessing COVID-19 employee protocols, minimizing the numbers of people in our offices at times, conducting daily health screenings for all employees and visitors, and completing thorough contact tracing. These efforts helped protect the safety of employees, minimize the risk of transmission at Gulfport locations and keep our operations online with minimal disruption.

Inclusion & Diversity

During 2021, we continued to work on the diversity and inclusion projects that we announced in 2020 and held peer-led, small group discussions for all employees aimed at understanding how they view diversity and ways we could continue to focus on it in a meaningful way going forward. Based partly on feedback from those discussions, the Company delivered an unconscious bias training program for all employees to better help them understand themselves and how they view those around them. The results of these efforts have been overwhelmingly positive and have positioned us to further our diversity and inclusion initiatives in 2022 and beyond.

During 2021, our Board of Directors completely turned over as a result of the bankruptcy process and is now comprised of 40% of highly qualified diverse candidates as of the end of 2021. While 2021 was a year in which we again added very few new employees, approximately 29% of our newly hired employees were diverse hires. We are committed to evaluating our hiring and promotion practices to make sure that a diversity and inclusion mindset is considered and included throughout the Company.

In 2021, many Gulfport policies were added or revised, and a new Business Code of Conduct and Ethics training was provided to all employees. We are committed to maintaining the highest standards of business ethics and the employee training provided a clear review of our expectations.

Health, Safety & Environment (HSE)

Safety is at the forefront of everything we do. We have a robust annual training program, which includes environmental, health, and safety topics. Our safety program, WORK SAFE, is comprised of twelve key topics including critical tasks and cultural conditions. We hold regular safety briefings to discuss daily operations and routinely have safety stand-down meetings to highlight potential risks. Every employee is empowered to use their stop-work authority to cease operating if work is being performed in an unsafe manner. We monitor employee safety by establishing annual company-wide key safety metrics tied to leading indicators (i.e., incident reporting and investigations, hazard observations, safety and health meetings) and lagging indicators (i.e., injury rates and preventable motor vehicle accidents).

As part of our focus on continuous improvement, we monitor and communicate key environmental and safety metrics both internally and externally. Trend analysis guides us to make operational changes and policy updates as necessary to protect our employees, the public, and the environment. We establish and carefully track key environmental and safety metrics that are a component of every employee’s incentive compensation opportunity for 2021.

We have established several programs to ensure that our employees and external partners are appropriately trained to perform the critical work we do safely and effectively. We continued to reinforce our Work Safe Program and provided training to leaders on reinforcement strategies. Additionally, we launched the Work Green program in 2021, which focuses on protecting the air, land and water where we operate and includes community-based volunteer events targeting environmental clean-up and habitat improvement initiatives.

Training & Development

Gulfport invests in our employees' professional growth to build strong teams and develop leaders for today and the future. We build our dynamic team of industry-leading professionals by engaging them in interesting and rewarding work and by providing training and development opportunities. We utilize in-person training sessions developed by safety experts and supplement these sessions with computer-based modules to support a safety-first mindset in everything we do. We continue to provide training resources to employees through universities, electronic content services and specialized courses related to our industry through our tuition reimbursement program or third-party providers.

Executive Officers

Timothy J. Cutt, Chief Executive Officer and Chairman of the Board

Mr. Cutt, 61, joined Gulfport as the Interim Chief Executive Officer in May 2021, and assumed the role of Chief Executive Officer in September 2021. Mr. Cutt is a Petroleum Engineer with 38 years of energy experience. He served as Chief Executive Officer and as a director of QEP Resources from January 2019 to March 2021. Prior to joining QEP, Mr. Cutt was the Chief Executive Officer and a director of Cobalt International Energy from 2016 to 2018. Previously, Mr. Cutt held several executive positions with BHP Billiton before serving as President of the Petroleum Division from 2013 to 2016. During this time, he was also a member of BHP Billiton’s Corporate Leadership Team. Mr. Cutt began his career with Mobil and worked for ExxonMobil for 24 years and served in various management roles including President of ExxonMobil de Venezuela, President ExxonMobil Canada Energy and President Hibernia Management & Development Company. Mr. Cutt served as a board member of the American Petroleum Institute (API) from 2013 to 2018.

William J. Buese, Chief Financial Officer

Mr. Buese, 50, joined Gulfport as the Chief Financial Officer in May 2021. Most recently, Mr. Buese served as Vice President, Chief Financial Officer and Treasurer of QEP Resources from January 2020 to March 2021. He joined QEP Resources in 2012 and held positions of increasing responsibility over a nine-year period, including Vice President of Finance and Treasurer and Director of Finance. Prior to joining QEP, Mr. Buese was Director of Finance at MarkWest Energy Partners, LP and served in various finance, treasury, accounting and investor relations roles from 2005 to 2012. Mr. Buese holds over 16 years of financial expertise in the energy industry and more than 25 years of financial experience overall. Mr. Buese received his Bachelor of Arts degree in Accounting from Michigan State University and Master of Science degree in Information Systems from the University of Colorado Denver.

Patrick K. Craine, Chief Legal and Administrative Officer

Mr. Craine, 49, has served as Chief Legal and Administrative Officer since June 2021 and joined Gulfport as Executive Vice President, General Counsel and Corporate Secretary in May 2019. Prior to joining the Company, Mr. Craine served as

Deputy General Counsel – Chief Risk and Compliance Officer at Chesapeake Energy Corporation. Prior to joining Chesapeake in 2013, Mr. Craine was a partner with Bracewell LLP, a global law firm, where his practice focused on securities and corporate regulatory matters and investigations. Before Mr. Craine entered private practice, he served as a lawyer with the U.S. Securities and Exchange Commission and the Financial Industry Regulatory Authority where he held leadership positions in their Oil and Gas Task Forces. Mr. Craine has over 20 years of extensive senior-level experience handling a broad range of securities, corporate, regulatory, governance, compliance and litigation matters, with particular expertise in the energy industry. Mr. Craine received his Bachelor of Arts degree, summa cum laude, Phi Beta Kappa, from Wabash College, and his Juris Doctorate, cum laude, from the Southern Methodist University Dedman School of Law.

Michael J. Sluiter, Senior Vice President of Reservoir Engineering

Mr. Sluiter, 49, joined Gulfport as the Senior Vice President of Reservoir Engineering in December 2018 from Noble Energy, Inc., where he most recently served as the Permian Basin Business Unit Manager at Noble Energy, Inc. Prior to joining Noble in 2007, he spent over 17 years developing his skills and expertise in unconventional resource development, reservoir engineering, subsurface development, business development/M&A, and leadership at Noble Energy, Santos Australia and Santos USA. Mr. Sluiter began his career as a wireline field services engineer for Schlumberger in Thailand. Mr. Sluiter is a graduate of the University of Sydney, Australia, with a Bachelor of Science degree in Chemical Engineering.

RJ Moses, Senior Vice President of Operations and Drilling

Mr. Moses, 42, has served as Senior Vice President of Operations and Drilling since March 2020 and joined Gulfport Energy as the Vice President of Operations, Appalachia in August 2019. Prior to joining the Company, Mr. Moses spent over 15 years at Noble Energy, Inc., where he most recently served as a Director of Operations for Noble’s Eagleford and Denver-Julesburg (DJ) business units, managing approximately one-third of Noble’s total production at the time. Prior to that, he held various leadership roles including Operations Manager for Noble’s Marcellus business unit along with several international roles including Asset Manager for the Tamar asset (offshore Israel), Project Manager for West Africa subsea development and Lead Reservoir Engineer for West Africa. In addition, Mr. Moses served as a Senior Financial Analyst in the International division and also spent four years as an international drilling and completion engineer for Noble. Mr. Moses graduated from Texas A&M University with a Bachelor of Science degree in Petroleum Engineering and holds a Master of Business Administration degree from Texas Christian University.

There is no family relationship between any of our officers or between any of them and the Company's Board of Directors. The executive officers serve at the pleasure of the Company's Board of Directors.

ITEM 1A. RISK FACTORS

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a summary of significant factors 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, operating results, cash flows, reserves 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.

Financial, Liquidity and Commodity Price Risks

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, cash flows, profitability, future rate of growth, production and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for natural gas and, to a lesser extent, oil and NGL. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, periods of low natural gas, oil and NGL prices may result in ceiling test write-downs of our oil and natural gas properties.

Historically, the markets for natural gas, oil and NGL have been volatile, and they are likely to continue to be volatile. For example, during 2020, West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, prices ranged from $(36.98) to $63.27 per barrel and the Henry Hub spot market price of natural gas ranged from $1.33 to $3.14 per MMBtu. During 2021, WTI prices ranged from $47.47 to $85.64 per barrel and the Henry Hub spot market price of natural gas ranged from $2.43 to $23.86 per MMBtu.

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

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- the level of prices, and expectations about future prices, of oil and natural gas;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns, such as the recent coronavirus;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil, natural gas, liquefied natural gas and NGL;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil price and production controls;
- political or economic instability or armed conflict in oil and natural gas producing regions, including the Middle East, Africa, South America and Russia;
- weather conditions;
- acts of terrorism; and

• domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. Even with natural gas, oil and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2022 cash flows, we have substantial exposure to natural gas prices, and to a lesser extent, oil and NGL prices, in 2023 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil and natural gas 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 also may be unable to mitigate price volatility due to our exposure to long-dated call options and restrictions in our credit facility. We may choose not to enter into derivatives if the pricing environment for certain time periods is not deemed to be favorable. 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.

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 its 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.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility. Our revolving credit facility is structured under floating rate terms. As such, our interest expense is sensitive to fluctuations in the London Interbank Offered Rate. At December 31, 2021, amounts borrowed under our revolving credit facility bore interest at the weighted average rate of 3.19%. A 1% increase in the average interest rate would increase our interest expense by approximately $2 million based on outstanding borrowings under our revolving credit facility at December 31, 2021. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our revolving credit facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition. As of December 31, 2021, we did not hedge our interest rate risk.

We have exposure to LIBOR through credit agreements. Certain tenors of LIBOR began being phased out in late 2021, with full discontinuation planned for mid-2023. We believe the rate selected as the preferred alternative to LIBOR will be an acceptable replacement rate when LIBOR is fully discontinued. However, we are still currently evaluating the impact of any such potential benchmark replacements or unavailability of LIBOR. In addition, the overall financial markets may be disrupted as a result of the phase-out or replacement of LIBOR. Uncertainty as to the nature of such potential phase-out and alternative benchmark rates or disruption in the financial markets could materially and adversely affect our financial condition, results of operations and cash flows.

Our debt and other financial commitments may limit our financial and operating flexibility.

Our total principal debt was approximately $714 million at December 31, 2021. We also had various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services, products and properties. Our financial commitments could have important consequences to our business, including, but not limited to, limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, to pay dividends, to repurchase shares of our common and preferred stock, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flows from operations to make payments on our debt or to comply with restrictive terms of our debt. Higher levels of debt may make us more vulnerable to general adverse economic and industry conditions. Additionally, the agreement governing our credit facility and the indentures governing our senior notes contain a number of covenants that impose constraints on us, including requirements to comply with certain financial covenants and restrictions on our ability to dispose of assets, make certain investments, incur liens and additional debt, and engage in consolidations, mergers and acquisitions. If commodity prices decline and we reduce our level of capital spending and production declines or we incur additional impairment expense or the value of our proved reserves declines, we may not be able to incur additional indebtedness, may need to repay outstanding indebtedness and may not be in compliance with the financial covenants in our debt instruments in the future. Refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of this Annual Report on Form 10-K and Note 6 of our consolidated financial statements for more information regarding the financial covenants and our revolving credit agreement.

Our development, acquisition and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves.

Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity and debt securities and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- our ability to acquire, locate and produce economically new reserves; and
- our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2022 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies.

Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations.Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proved oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting oil and NGLs to one MCF of natural gas at the ratio of six Mcf of natural gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter.The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the unweighted arithmetic average of the closing prices on the first day of each month for the 12-month period ending at the balance sheet date, adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash write-down is required. A ceiling test impairment can result in a significant loss for a particular period.Once incurred, a write-down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. Future non-cash asset impairments could negatively affect our results of operations.

A change of control could limit our use of net operating losses to reduce future taxable income.

As of December 31, 2021, we had a net operating loss, or NOL, carryforward of approximately $1.4 billion for federal income tax purposes. If we were to experience an “ownership change,” as determined under IRC Section 382, our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate for the month in which such ownership change occurs. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more “5% shareholders” (as defined in the Code) at any time during a rolling three-year period.

Emergence from Chapter 11 bankruptcy proceedings resulted in an ownership change for purposes of IRC Section 382. We currently expect to apply rules under IRC Section 382(l)(5) that would allow us to mitigate the limitations imposed under IRC Section 382 with respect to our NOLs that existed at the time of such ownership change. However, if we were to experience a second ownership change, then our ability to utilize our NOLs could potentially be subject to a more restrictive limitation under IRC Section 382.

Industry, Business and Operational Risks

The oil and gas development, exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.

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 and, due to our debt levels and other factors, may have greater access to the capital and credit markets. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. As a result, these competitors may be able to address these competitive factors 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.

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

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

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

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to 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 oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2021, approximately 44% of our total estimated proved reserves were PUDs and may not be ultimately developed or produced. Recovery of PUDs requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. 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. Delays in the development of our reserves, further decreases in commodity prices or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. 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, 2021 present value is based on a $3.60 per MMBtu of gas price and a $66.55 per Bbl of oil price, before considering basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Actual future net revenues from our oil and natural gas properties will also be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

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

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

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We acquire significant amounts of unproven properties that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive, or that we will recover all or any portion of our investment in such undeveloped properties or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling and completion operations may be curtailed, delayed or cancelled 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, 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. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations. All costs of development and exploratory drilling activities are capitalized under the full cost method, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

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

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the development activities we employ, such as offset drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of offset drilling, adjacent wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Although 80% of our Utica acreage is held by existing production, the remaining acreage is subject to expiration. Of the remaining 20% of our Utica acreage not held by production, 39% will be subject to expiration in 2022, 35% in 2023, 8% in 2024 and 18% thereafter, although a portion of our Utica leases generally grant us the right to extend these leases for an additional five-year period. Although 99% of our SCOOP acreage is held by existing production, the remaining acreage is subject to expiration. Of the remaining 1% of our SCOOP acreage not held by production, 17% will be subject to expiration in 2022, 6% in 2023, 77% in 2024 and none thereafter. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. If we are unable to fund renewals of expiring leases, we could lose portions of our acreage and our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our oil and natural gas operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, natural gas and NGL can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. While 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. For the 9% of our daily production volumes from properties which we did not serve as operator as of December 31, 2021, we are dependent on the operator for operational and regulatory compliance. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or cancelled 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;
- loss of drilling fluid circulation;
- equipment failures or accidents;

- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives;
- 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, including liabilities for environmental damage caused by previous owners of properties purchased by us;
- 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 opinions.

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.

While 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, cybersecurity breaches, 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 uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Multi-well pad drilling may result in volatility in our operating results and delay the conversion of our PUD reserves.

We utilize multi-well pad drilling where practical. For example, in the Utica we drill multiple wells from a single pad. Wells drilled on a pad are not turned to sales until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells and the commencement of production from new wells, and may negatively affect the production from existing offset wells, all of which may cause volatility in our operating results from period to period. Finally, delays in completion of wells may impact planned conversion of PUD reserves to PDP reserves.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are not the operator of all of the properties in which we have an interest, and have limited ability to exercise influence over the operations of such non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploration activities on properties operated by others will depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and

- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. 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.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. For water sourcing, we first seek to use non-potable water supplies for our operational needs. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must then be obtained from other sources and transported to the drilling site. An 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 new environmental regulations could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of things such as produced water and drilling fluids.

Substantially all of our producing properties are located in Eastern Ohio and Oklahoma, making us vulnerable to risks associated with operating in only these regions.

Our largest fields by production are located in Eastern Ohio and Oklahoma. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production in these geographic regions caused by weather conditions such as snow, ice, fog, rain, hurricanes, tornados or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable and it is possible that certain types of coverage may not be available.

The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.

The largest purchaser of our oil and natural gas during the Predecessor Period and Successor Period accounted for approximately 14% and 20%, respectively, of our total natural gas, oil and NGL revenues. If this purchaser or one or more other significant purchasers, are unable to satisfy its contractual obligations, we may be unable to sell such production to other customers on terms we consider acceptable. Further, the inability of one or more of our customers to pay amounts owed to us could adversely affect our business, financial condition, results of operations and cash flows.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for and wage rates of qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of and increased costs for drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

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.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations.

With respect to our Utica acreage where we are focusing a portion of our exploration and development activity, historically there has been no or only limited infrastructure in this area and the commencement of production from our initial and subsequent wells on our Utica acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider. Capital constraints could limit the construction of new pipelines and gathering systems and the providing or expansion of trucking services by third parties in the Utica and the other areas in which we operate. 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 awaiting a pipeline connection or capacity or sell natural gas, oil or NGL production at significantly lower prices than those quoted on NYMEX or than we currently project, 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.

We are required to pay fees to some of our midstream service providers based on minimum volumes regardless of actual volume throughput.

We have contracts with some of our third-party service providers for gathering, processing and transportation services with minimum volume delivery commitments under which we are obligated to pay certain fees on minimum volumes regardless of actual volume throughput. As of December 31, 2021, our aggregate long-term contractual obligation under these agreements was approximately $1.8 billion. These fees could be significant and may have a material adverse effect on our results of operations.

The outbreak of the novel coronavirus, or COVID-19, has affected and may materially adversely affect, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our operations, financial performance and condition, operating results and cash flows.

The recent outbreak of COVID-19 has affected, and may materially adversely affect, our business and financial and operating results. The severity, magnitude and duration of the current COVID-19 outbreak is uncertain, rapidly changing and hard to predict. In 2021, the outbreak has significantly impacted economic activity and markets around the world, and COVID-19 or another similar outbreak could negatively impact our business in numerous ways, including, but not limited to, the following:

- our revenue may be reduced if the outbreak results in an economic downturn or recession, as many experts predict, to the extent it leads to a prolonged decrease in the demand for natural gas and, to a lesser extent, NGL and oil;
- our operations may be disrupted or impaired, thus lowering our production level, if a significant portion of our employees or contractors are unable to work due to illness or if our field operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the outbreak;
- the operations of our midstream service providers, on whom we rely for the transmission, gathering and processing of a significant portion of our produced natural gas, oil and NGL, may be disrupted or suspended in response to containing the outbreak, and/or the difficult economic environment may lead to the bankruptcy or closing of the facilities and infrastructure of our midstream service providers, which may result in substantial discounts in the prices we receive for our produced natural gas, oil and NGL or result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties; and

- the disruption and instability in the financial markets and the uncertainty in the general business environment may affect our ability to execute on our business strategy, including our focus on reducing our leverage profile. If we are not able to successfully execute our plan to reduce our leverage profile, our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations under any of our debt instruments, including their restrictive covenants, could result in a default under our revolving credit facility or the indentures governing our senior notes. Additionally, our credit ratings may be lowered, we may reduce or delay our planned capital expenditures or investments, and we may revise or delay our strategic plans.

We expect that the principal areas of operational risk for us are availability of service providers and supply chain disruption, which has recently become more acute. Active development operations, including drilling and fracking operations, represent the greatest risk for transmission given the number of personnel and contractors on site. While we believe that we are following best practices under COVID-19 guidance, the potential for transmission still exists. In certain instances, it may be necessary or determined advisable for us to delay development operations.

In addition, the COVID-19 pandemic has increased volatility and caused negative pressure in the capital and credit markets. As a result, we may experience difficulty accessing the capital or financing needed to fund our exploration and production operations, which have substantial capital requirements, or refinance our upcoming maturities on satisfactory terms or at all. We typically fund our capital expenditures with existing cash and cash generated by operations (which is subject to a number of variables, including many beyond our control) and, to the extent our capital expenditures exceed our cash resources, from borrowings under our revolving credit facility and other external sources of capital. If our cash flows from operations or the borrowing capacity under our revolving credit facility are insufficient to fund our capital expenditures and we are unable to obtain the capital necessary for our planned capital budget or our operations, we could be required to curtail our operations and the development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, results of operations and financial position.

To the extent the COVID-19 pandemic adversely affects our business and financial results, it may also have the effect of heightening many of the other risks set forth in Item 1A., “Risk Factors” in our Annual Report on Form 10-K, such as those relating to our financial performance and debt obligations. The rapid development and fluidity of this situation precludes any prediction as to the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments that we are not able to predict, including the length of time that the pandemic continues, its effect on the demand for natural gas, NGL and oil, the response of the overall economy and the financial markets as well as the effect of governmental actions taken in response to the pandemic.

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

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the United States financial markets have contributed to economic volatility and diminished expectations for the global economy. Historically, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic 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.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have in the past precipitated, and may in the future precipitate, an economic slowdown.

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

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the 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, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyber-attack involving our information systems and related infrastructure, or that of our business associates, 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, supplier's or royalty owners' 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.

In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any 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, and any failure to comply with these laws and regulations could result in significant penalties and legal liability.

We may engage in acquisition and divestiture activities that involve substantial risks.

We may make acquisitions that complement or expand our current areas of operations.If we are unable to make attractive acquisitions, our future growth could be limited. Furthermore, even if we do make acquisitions, they may not result in an increase in our cash flow from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- mistaken estimates or assumptions about reserves, potential drilling locations, revenues and costs, including synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

In addition, from time to time, we may sell or otherwise dispose of certain of our properties or businesses as a result of an evaluation of our asset portfolio or to help enhance our liquidity. These transactions also have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets or businesses and potential post-closing claims for indemnification. Moreover, volatility in commodity prices may result in fewer potential bidders, unsuccessful sales efforts and a higher risk that buyers may seek to terminate a transaction prior to closing.

Legal and Regulatory Risks

We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.

Our operations are subject to extensive federal, state, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. For example, on January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. To the extent that the review results in the development of additional restrictions on drilling, limitations on the availability of leases, or restrictions on the ability to obtain required permits, it could have a material adverse impact on our operations. In addition, we may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory changes could, among other things, restrict production levels, impose price controls, alter environmental protection requirements 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 or 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. As is discussed below this is particularly true of changes related to pipeline safety, seismic activity, hydraulic fracturing, climate change and endangered species designations.

Pipeline Safety. The pipeline assets owned by our midstream service providers 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 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. 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, and any such costs incurred by our midstream service providers could result in increased midstream gathering and processing expenses for us. Moreover, violations of pipeline safety regulations by our midstream service providers could result in the imposition of significant penalties which may impact the cost or availability of pipeline capacity necessary for our operations.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. For example, the OCC issued guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing or water disposal activities. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we could be subject to third-party lawsuits seeking damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. Three states (New York, Maryland and Vermont) have banned the use of high-volume hydraulic fracturing. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. There have also been certain governmental reviews that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Governments may continue to study hydraulic fracturing. We cannot predict the outcome of future studies, but based on the results of these studies to date, federal and state legislatures and agencies may seek to further regulate or even ban hydraulic fracturing activities. In addition, if existing laws and regulations with regard to hydraulic fracturing are revised or reinterpreted or if new laws and regulations become applicable to our operations through judicial or administrative actions, our business, financial condition, results of operations and cash flows could be adversely affected.

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 and incentivize energy conservation or the use of alternative energy sources. 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 or taxes on greenhouse gas emissions and encourage consumers to the alternative energy sources. The Build Back Better Act, passed by the US House of Representatives and supported by President Biden, includes incentives to increase wind and solar electric generation and encourage consumers to use these alternative energy sources. States in which we operate have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of cap and trade 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 or other initiatives to incentivize the use of renewable energy could reduce the demand for oil and gas, thereby adversely impacting our earnings, cash flows and financial position. Cap and trade programs offer greenhouse gas emission allowances that are gradually reduced over time. A cap and trade program or expanded use of cap and trade programs at the state level could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. In addition, federal or state carbon taxes could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Members of the investment community have also begun to screen companies such as ours for sustainability performance, including practices related to greenhouse gases and climate change, before investing in our common units. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are not economically viable to improve our sustainability performance and to meet the specific requirements to perform services for certain customers. If we are unable to meet the ESG standard or investment, lending, ratings, or voting criteria and policies set by these parties, we may lose investors, investors may allocate a portion of their capital away from us, we may become a target for ESG-focused activism, our cost of capital may increase, the price of our securities may be negatively impacted, and our reputation may also be negatively affected.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity. Furthermore, increasing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

Severe weather events, such as storms, hurricanes, droughts, or floods, could have an adverse effect on our operations and could increase our costs. If climate changes result in more intense or frequent severe weather events, the physical and disruptive effects could have a material adverse impact on our operations and assets.

Air Emissions. The US Federal Clean Air Act and associated state laws and regulations restrict the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before operations can commence, and existing facilities may be required to obtain additional permits, and incur capital costs, in order to remain in compliance. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. In general, we believe that compliance with the Clean Air Act and similar state laws and regulations will not have a material impact on our operations or financial condition.

Endangered Species. The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells.

In our Utica and SCOOP operations, we make an effort to reuse/recycle all produced water from production and completion activities through our fracture stimulation operations when active. While our objective is to recycle or share 100% of all produced water, we do inject water into third-party commercially operated disposal wells in line with all state and federal mandated practices and cease produced water recycle whenever fracture stimulation operations are idle once sharing opportunities with other operators have been exhausted. In the state of Ohio, all water used during drilling operations is disposed of through injection into third-party salt water disposal wells regulated by applicable state agencies.

Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and gas industry. For example, legislative proposals have been introduced in the U.S. Congress in the past that, if enacted, would (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) repeal the percentage depletion allowance for oil and natural gas properties, and (iii) extend the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. In addition, at the state level, legislative changes imposing increased taxes on oil and gas production have periodically been considered in Ohio and Oklahoma. These proposed changes in the U.S. federal and state tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flows.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate our costs as we collect and store personal data related to royalty owners. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. For example, the California Consumer Privacy Act (“CCPA”) was signed into law on June 28, 2018 and largely took effect on January 1, 2020. The CCPA, among other things, contains new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provides for statutory fines for data security breaches or other CCPA violations. Meanwhile, over fifteen other states have considered privacy laws like the CCPA. We will continue to monitor and assess the impact of these state laws, which may impose substantial penalties for violations, impose significant costs for investigations and compliance, require us to change our business practices, allow private class-action litigation and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in heightened risk of litigation, including private rights of action, and proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyber incidents or attacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

Risks Associated with our Emergence from Bankruptcy

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

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

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

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

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

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

Upon emergence from bankruptcy, the composition of our board of directors changed significantly.

The composition of our board of directors changed significantly upon emergence from bankruptcy. Our new board is comprised of five directors, including the Company's Chief Executive Officer, Timothy Cutt, and four non-employee directors, David Wolf, Guillermo Martinez, Jason Martinez and David Reganato. While we expect to engage in an orderly transition process as we integrate newly appointed board members, our new board of directors may change views on strategic initiatives and a range of issues that will determine the future of the Company. As a result, the future strategy and plans of the Company may differ materially from those of the past.

Risks Associated with an Investment in Us

The market price of our securities is subject to volatility.

Upon our emergence from bankruptcy, our old common stock was cancelled and we issued New Common Stock.The market price of our New Common Stock could be subject to wide fluctuations in response to, and the level of trading that develops with our New Common Stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the Plan, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the lack of comparable historical financial information due to our adoption of fresh start accounting, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this Part I, Item 1A of this Annual Report on Form 10-K.

Future sales or the availability for sale of substantial amounts of our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and could impair our ability to raise capital through future sales of equity securities.

A large percentage of our common stock is held by a relatively small number of investors. In connection with our emergence from bankruptcy protection, we entered into the Registration Rights Agreement pursuant to which we have agreed to file a registration statement with the SEC to facilitate potential future sales of our common stock by such investors. Sales of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur (such as upon the filing of the aforementioned registration statement), could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We cannot predict the effect that future sales of our common stock will have on the price at which the common stock trades. Sales of substantial amounts of our common stock, or the perception that such sales could occur, may adversely affect the trading price of our common stock.

Certain of our stockholders own a significant portion of our outstanding debt and equity securities and their interests may not always coincide with the interests of other holders of the New Common Stock.

A large percentage of our debt and equity are held by a relatively small number of investors. As a result, these investors could have significant influence over all matters presented to our stockholders and debt holders for approval, including election and removal of our directors, change in control transactions and the outcome of all actions requiring majority stockholder approval.

The interests of these investors may not always coincide with the interests of the other holders of the New Common Stock and other debt holders, and the concentration of control in these investors may limit other stockholders' ability to influence corporate matters. The concentration of ownership and voting power of these investors may also delay, defer or even prevent an acquisition by a third party or other change of control transactions of our Company. This may make some transactions more difficult or impossible without their support, even if such events are in the best interests of our other stockholders. In addition, the concentration of voting power may adversely affect the trading price and liquidity of the New Common Stock.

There may be future dilution of our common stock, which could adversely affect the market price of our common stock.

We are not restricted from issuing additional shares of our common stock. In the future, we may issue shares of our common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. We may also issue securities that are convertible into, exchangeable for or that represent the right to receive our common stock. Lastly, we currently issue restricted stock units and performance vesting restricted stock units to certain employees and directors as part of their compensation. Any of these events will dilute our shareholders' ownership interest in Gulfport and may reduce our earnings per share and have an adverse effect on the price of our common stock.

Our amended and restated certificate of incorporation provides, subject to certain exceptions, that the Court of Chancery of the State of Delaware will be the sole and exclusive forum for certain stockholder litigation matters, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

Our amended and restated certificate of incorporation provides, subject to limited exceptions, that the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf; (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors or officers to us, our stockholders, our creditors or other constituents; (iii) any action asserting a claim against us, any director or our officers arising pursuant to any provision of the DGCL, our certificate of incorporation or our by-laws; or (iv) any action asserting a claim against us, any director or our officers that is governed by the internal affairs doctrine. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or any of our directors or officers or stockholders which may discourage lawsuits with respect to such claims. Alternatively, if a court were to find the choice of forum provision contained in our certificate of incorporation to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such action in other jurisdictions, which could have a material adverse effect on our business, financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1 and in the Supplemental Information on Oil and Gas Exploration and Production Activities in Note 20 of our consolidated financial statements.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business.

While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

The information with respect to this Item 3. Legal Proceedings is set forth in Note 19 of our consolidated financial statements. Additionally, see Note 1 and Note 2 of our consolidated financial statements for additional discussion of on-going claims and disputes from our Chapter 11 proceedings, certain of which may be material.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Common Stock

On November 27, 2020, our predecessor common stock was suspended from trading on NASDAQ. On November 30, 2020, our predecessor common stock began trading on the OTC Pink Marketplace maintained by the OTC Markets Group, Inc. under the symbol "GPORQ". On February 2, 2021, NASDAQ filed a Form 25 delisting our predecessor common stock from trading on NASDAQ, which delisting became effective 10 days after the filing of the Form 25. In accordance with Rule 12d2-2 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the de-registration of our predecessor common stock under section 12(b) of the Exchange Act became effective on February 12, 2021.

On the Emergence Date, the predecessor common stock noted above was cancelled and we issued shares of new common stock. Shares of our new common stock are listed on the NYSE under the symbol "GPOR". See Note 7 of our consolidated financial statements for further discussion of our new common stock.

Shareholders

At the close of business on February 25, 2022, there were approximately 450 holders of record of our New Common Stock.

Dividends

We never paid dividends on our predecessor common stock. Subsequent to our emergence, we did not pay dividends on our New Common Stock in 2021. The declaration and payment of any future common stock dividend will be at the full discretion of the Board of Directors and will depend on our financial results, cash requirements, future prospects and other factors deemed relevant by our Board. Our New Credit Facility also requires us to meet certain financial covenants at the time dividend payments are made.

During the Successor Period, the company paid dividends on its New Preferred Stock, which included 3,071 shares of New Preferred Stock paid in kind, approximately $55 thousand of cash-in-lieu of fractional shares, and $1.5 million of cash dividends to holders of our New Preferred Stock.

Issuer Purchases of Equity Securities

On November 2, 2021, Gulfport announced the authorization by its Board of Directors to repurchase up to $100 million of the Company's outstanding shares of common stock through December 31, 2022. Purchases under the Repurchase Program may be made from time to time in open market or privately negotiated transactions, and will be subject to available liquidity, market conditions, credit agreement restrictions, applicable legal requirements, contractual obligations and other factors. The Repurchase Program does not require us to acquire any specific number of shares of New Common Stock. We intend to purchase shares under our Repurchase Program opportunistically with available funds while maintaining sufficient liquidity to fund our capital development program.

The Company did not repurchase any common stock during the year ended December 31 2021.

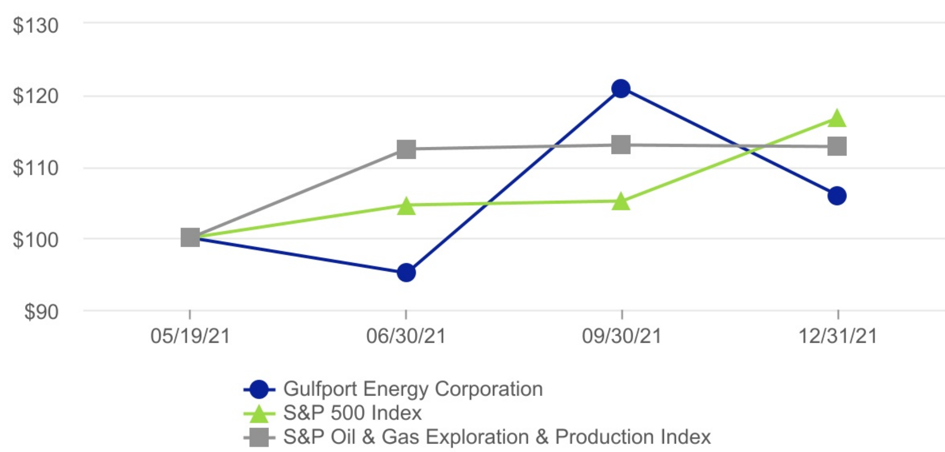
Recent Sales of Unregistered Securities

None.

Stock Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission ("SEC"), nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The performance graph below illustrates changes over the period of May 19, 2021 through December 31, 2021, in cumulative total stockholder return on the Successor common stock as measured against the cumulative total return of the S&P 500 Index and the S&P Oil & Gas Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from May 19, 2021 to December 31, 2021.



ITEM 6. [RESERVED]

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

The following discussion and analysis represents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report. The following information updates the discussion of Gulfport's financial condition provided in its 2020 Annual Report on Form 10-K filing and analyzes the changes in the results of operations between the years ended December 31, 2021 and 2020. Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 that are not included in this Form 10-K can be found in "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2020.

Our results of operations as reported in our consolidated financial statements for the Successor Period and the Predecessor Period are in accordance with GAAP. Although GAAP requires that we report on our results for these periods separately, management views our operating results for the twelve months ended December 31, 2021, by combining the results of the Successor Period and the Predecessor Period ("Combined Period"). While these combined results do not comply with GAAP and have not been prepared as pro forma results under applicable regulations, they are presented because we believe they provide the most meaningful comparison of our results to prior periods. We do not believe reviewing these periods 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 operating expenses for the Successor Period combined with the Predecessor Period provide more meaningful comparisons to other periods and are useful in understanding operational trends. Additionally, there were no material 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.

Overview

Gulfport is an independent natural gas-weighted exploration and production company with assets primarily located in the Appalachia and Anadarko basins. Our principal properties are located in Eastern Ohio targeting the Utica and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations. Our strategy is to develop our assets in a safe, environmentally responsible manner, while generating sustainable cash flow, improving margins and operating efficiencies and returning capital to shareholders. To accomplish these goals, we allocate capital to projects we believe offer the highest rate of return and we deploy leading drilling and completion techniques and technologies in our development efforts.

Recent Developments

Emergence from voluntary reorganization under Chapter 11

On November 13, 2020, we and our subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases were administered jointly under the caption *In re Gulfport Energy Corporation, et al.,* Case No. 20-35562 (DRJ). The Bankruptcy Court confirmed the Plan and entered the confirmation order on April 28, 2021, and the Debtors emerged from the Chapter 11 Cases on the Emergence Date. On May 18, 2021, we began trading on the New York Stock Exchange under the symbol "GPOR."

Although we are no longer a debtor-in-possession, we operated as debtors-in-possession through the pendency of the Chapter 11 Cases. See Note 1 and Note 2 of our consolidated financial statements for a complete discussion of the Chapter 11 Cases.

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. As a result of the Chapter 11 Cases, we reduced our total indebtedness by $1.4 billion by issuing equity in a reorganized entity to the holders of our unsecured notes and allowed general unsecured claimants. In addition, we reassessed our organizational needs post emergence and significantly reduced our general and administrative expense to ensure our cost structure is competitive with industry peers. We continue to focus on reducing our operating costs, per well drilling costs, general and administrative costs and managing our liquidity. We believe our plan to generate free cash flow on an annual basis will allow us to further strengthen our balance sheet and return capital to shareholders.

Changes in Chief Executive Officer and Chief Financial Officer

On May 17, 2021, the Board reached agreements with David M. Wood and Quentin R. Hicks that Messrs. Wood and Hicks would no longer serve as Chief Executive Officer and a member of the Board, in the case of Mr. Wood, and Chief Financial Officer, in the case of Mr. Hicks.

On May 17, 2021, the Board appointed Timothy J. Cutt as Interim Chief Executive Officer and Chair of the Board. On September 2, 2021, we reached agreement with Mr. Cutt, effective immediately, to fully assume the role of Chief Executive Officer, dropping the "Interim" designation from his title.

On May 17, 2021, the Board appointed William J. Buese as Chief Financial Officer.

New Credit Facility

On October 14, 2021, we entered into the New Credit Facility for an aggregate maximum principal amount of up to $1.5 billion, an initial borrowing base of $850.0 million and an initial aggregate elected commitment amount of $700.0 million. The New Credit Facility amended and refinanced the Exit Credit Facility. See Note 6 of our consolidated financial statements for additional discussion of the New Credit Facility.

Stock Repurchase Program

On November 1, 2021, our board of directors approved a stock repurchase program to acquire up to $100 million of our outstanding New Common Stock. Purchases under the Repurchase Program may be made from time to time in open market or privately negotiated transactions, and will be subject to available liquidity, market conditions, credit agreement restrictions, applicable legal requirements, contractual obligations and other factors. The Repurchase Program does not require the Company to acquire any specific number of shares of New Common Stock. The Company intends to purchase shares under the Repurchase Program opportunistically with available funds while maintaining sufficient liquidity to fund its capital development program. The Repurchase Program is authorized to extend through December 31, 2022, and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. Any shares of New Common Stock repurchased are expected to be cancelled. We have not repurchased any shares under this program as of December 31, 2021.

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

As a result of our business continuity measures, we have not experienced significant disruptions in executing our business operations due to COVID-19. While we did not experience significant disruptions to our operations in 2021, we are unable to predict the impact on our business, including our cash flows, liquidity, and results of operations in future periods due to numerous uncertainties. Restrictions may cause us, our suppliers and other business counterparties to experience operational delays, or delays in the delivery of materials and supplies. We expect the principal areas of operational risk for us are the availability and reliability of service providers and potential supply chain disruption. Additionally, the operations of our midstream service providers, on whom we rely for the transmission, gathering and processing of a significant portion of our produced natural gas, NGL and oil, may be disrupted or suspended in response to containing the outbreak, or the difficult economic environment may lead to the bankruptcy or closing of the facilities and infrastructure of our midstream service providers. This may result in substantial discount in the prices we receive for our produced natural gas, NGL and oil or result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties.

We cannot predict the full impact that COVID-19 or the significant disruption and volatility currently being experienced in the oil and natural gas markets will have on our business, cash flows, liquidity, financial condition and results of operations at this time, due to numerous uncertainties. The ultimate impacts will depend on future developments and the timing and extent to which normal economic and operating conditions resume.

2021 Operational and Financial Highlights

During 2021, we had the following notable achievements:

- Emerged from Chapter 11 proceedings in May 2021 with improved balance sheet and fixed-cost structure.
- In September 2021, we finalized a settlement agreement with TC Energy which rejected the firm transportation contracts between us and TC Energy without any further payment or obligation by us or TC. In exchange, we paid $43.8 million in cash to TC and expect to receive back a significant portion of such amount through future distributions with respect to the assigned claims.
- In October 2021, we amended and refinanced our Exit Credit Facility with the New Credit Facility. The amendment increased our elected commitment from $580 million to $700 million and increased our liquidity by more than $160 million.
- In December 2021, we reached an agreement with Stingray Pressure Pumping LLC that fully resolved the longstanding litigation between the parties.
- Turned to sales 28 gross (26.4 net); including the Angelo pad which flowed at a sustained, gross peak rate of 250 MMcfe per day after it was brought online in early October.
- Reported year-end estimated net proved reserves of 3.9 Tcfe.

Business and Industry Outlook

As discussed above, we emerged from voluntary reorganization under Chapter 11 in May 2021. Through our restructuring we were able to emerge with a strengthened balance sheet and materially improved fixed-cost structure. Gulfport is beginning this new chapter with a strategy focused on continuing to reduce costs and generating sustainable free cash flow in an effort to drive shareholder value. In addition, we are committed to an emphasis on sustainability, and we will continue to prioritize safety, environmental stewardship, and maintaining strong relationships with the communities in which we operate. As we enter 2022, we believe we are positioned for sustainable long-term success.

In 2021, natural gas prices improved significantly, but continue to be volatile as spot prices ranged from $2.43 to $23.86 per MMBtu. Henry Hub averaged $3.89 per MMBtu in 2021 vs $2.03 per MMBtu in 2020. As we look into 2022, we expect continued volatility in natural gas prices. To mitigate our exposure to commodity market volatility and ensure our continued financial strength we have entered into financial hedges representing approximately 86% of our expected 2022 production.

Our 2022 capital expenditure program is expected to be in a range of $340 million to $380 million. Prior to 2021, general inflation was moderate; however, our capital and operating costs were influenced to a large extent by the volatility in commodity prices. With the improved commodity price environment, we have experienced and expect to continue to experience inflationary pressures during 2022. We continue to monitor and manage inflationary pressures caused by increased activities in the field as well as supply chain pressures.

Results of Operations

Comparison of the Predecessor Period, Successor Period and the Year Ended December 31, 2020

We reported net income of $251.0 million for the Predecessor Period and a net loss of $112.8 million for the Successor Period, as compared to a net loss of $1.6 billion for the year ended December 31, 2020. The material changes that lead to the increase in net income are further discussed by category on the following pages. Some totals and changes throughout below section may not sum or recalculate due to rounding.

Natural Gas, Oil and NGL Sales (sales totals in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Natural gas (MMcf/day)				
Utica production volumes	732	781	750	795
SCOOP production volumes	183	126	162	147
Total production volumes	915	907	912	943
Total sales	$ 906,096	$ 344,390	$ 1,250,486	$ 671,535
Average price without the impact of derivatives ($/Mcf)	$ 4.34	$ 2.77	$ 3.76	$ 1.95
Impact from settled derivatives ($/Mcf)(1)	$ (1.44)	$ (0.03)	$ (0.91)	$ 0.33
Average price, including settled derivatives ($/Mcf)	$ 2.90	$ 2.74	$ 2.85	$ 2.28
Oil and condensate (MBbl/day)				
Utica production volumes	1	1	1	1
SCOOP production volumes	4	3	3	4
Total production volumes	5	4	4	5
Total sales	$ 81,347	$ 29,106	$ 110,453	$ 62,902
Average price without the impact of derivatives ($/Bbl)	$ 69.71	$ 54.81	$ 65.01	$ 34.88
Impact from settled derivatives ($/Bbl)(2)	$ (8.33)	$ —	$ (5.72)	$ 25.76
Average price, including settled derivatives ($/Bbl)	$ 61.38	$ 54.81	$ 59.29	$ 60.64
NGL (MBbl/day)				
Utica production volumes	2	3	3	3
SCOOP production volumes	9	6	8	8
Total production volumes	11	9	11	11
Total sales	$ 105,141	$ 36,780	$ 141,921	$ 66,814
Average price without the impact of derivatives ($/Bbl)	$ 39.56	$ 30.37	$ 36.68	$ 16.86
Impact from settled derivatives ($/Bbl)	$ (4.88)	$ —	$ (3.35)	$ (0.04)
Average price, including settled derivatives ($/Bbl)	$ 34.68	$ 30.37	$ 33.33	$ 16.82
Total (MMcfe/day)				
Utica production volumes	753	805	772	820
SCOOP production volumes	263	179	231	217
Total production volumes	1,016	983	1,003	1,037
Total sales	$ 1,092,584	$ 410,276	$ 1,502,860	$ 801,251
Average price without the impact of derivatives ($/Mcfe)	$ 4.72	$ 3.05	$ 4.10	$ 2.11
Impact from settled derivatives ($/Mcfe)	$ (1.39)	$ (0.02)	$ (0.89)	$ 0.42
Average price, including settled derivatives ($/Mcfe)	$ 3.33	$ 3.03	$ 3.21	$ 2.53

(1) In November 2020, the Company early terminated certain gas fixed-price swaps which resulted in a cash payment of $60.2 million.
(2) In April 2020, the Company early terminated certain oil fixed-price swaps which resulted in a cash receipt of $40.5 million.

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Natural gas sales	$ 906,096	$ 344,390	$ 1,250,486	$ 671,535
Oil and condensate sales	81,347	29,106	110,453	62,902
Natural gas liquid sales	105,141	36,780	141,921	66,814
Total natural gas, oil and condensate, and NGL sales	$ 1,092,584	$ 410,276	$ 1,502,860	$ 801,251

In the Combined Period, our total unhedged natural gas, oil and NGL revenues increased approximately $701.6 million, or 88%, as compared to the year ended December 31, 2020. The increase was primarily driven by significant increases in oil, natural gas and NGL indexes. Most notably, the Henry Hub index increased from $2.03 per MMBtu in 2020 to $3.89 per MMBtu in 2021. The impact of the realized price increases was partially offset by a decrease in volumes of 3%, or $28.7 million, as a result of natural declines partially offset by wells that were turned to sales during 2021.

The total natural gas, oil and NGL volumes hedged for the Combined Period and the year ended December 31, 2020, represented approximately 87% and 70%, respectively, of our total sales volumes for the applicable year.

Natural Gas, Oil and NGL Derivatives (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Natural gas derivatives - fair value (losses) gains	$ (223,512)	$ (123,080)	$ (346,592)	$ (89,310)
Natural gas derivatives - settlement (losses) gains	(300,172)	(3,362)	(303,534)	113,075
Total (losses) gains on natural gas derivatives	(523,684)	(126,442)	(650,126)	23,765
Oil and condensate derivatives - fair value losses	(5,128)	(6,126)	(11,254)	(2,952)
Oil and condensate derivatives - settlement (losses) gains	(9,720)	—	(9,720)	46,462
Total (losses) gains on oil and condensate derivatives	(14,848)	(6,126)	(20,974)	43,510
NGL derivatives - fair value losses	(5,322)	(4,671)	(9,993)	(461)
NGL derivatives - settlement losses	(12,965)	—	(12,965)	(142)
Total (losses) gains on NGL derivatives	(18,287)	(4,671)	(22,958)	(603)
Contingent consideration arrangement - fair value losses	—	—	—	(1,381)
Total (losses) gains on natural gas, oil and NGL derivatives	$ (556,819)	$ (137,239)	$ (694,058)	$ 65,291

Settlement (losses) gains in the table above represent realized cash gains or losses to the instruments described in Note 13 of our consolidated financial statements. Our hedging program incurred cash settlements of $326.2 million for the Combined Period, as compared to $159.4 million provided in 2020.

Lease Operating Expenses (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Lease operating expenses				
Utica	$ 21,841	$ 13,991	$ 35,832	$ 40,071
SCOOP	10,247	5,449	15,696	14,156
Other	84	84	168	8
Total lease operating expenses	$ 32,172	$ 19,524	$ 51,696	$ 54,235
Lease operating expenses per Mcfe				
Utica	$ 0.13	$ 0.13	$ 0.13	$ 0.13
SCOOP	0.17	0.22	0.19	0.18
Other	0.81	2.15	1.17	0.06
Total lease operating expenses per Mcfe	$ 0.14	$ 0.14	$ 0.14	$ 0.14

The decrease in total LOE when comparing the Combined Period to the year ended December 31, 2020, was primarily driven by a 3% decrease in our production. LOE on a per unit basis in 2021 was consistent with 2020.

Taxes Other Than Income (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Production taxes	$ 22,793	$ 8,459	$ 31,252	$ 17,511
Property taxes	5,266	2,590	7,856	9,510
Other	2,184	1,300	3,484	1,488
Total taxes other than income	$ 30,243	$ 12,349	$ 42,592	$ 28,509
Total taxes other than income per Mcfe	$ 0.13	$ 0.09	$ 0.12	$ 0.08

The increase in total and per unit taxes other than income when comparing the Combined Period to the year ended December 31, 2020, was primarily related to an increase in production taxes resulting from the significant increase in our natural gas, oil and NGL revenues excluding the impact of hedges discussed above.

Transportation, Gathering, Processing and Compression (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Transportation, gathering, processing and compression	$ 212,013	$ 161,086	$ 373,099	$ 456,318
Transportation, gathering, processing and compression per Mcfe	$ 0.92	$ 1.20	$ 1.02	$ 1.20

The decrease in transportation, gathering, processing and compression when comparing the Combined Period to the year ended December 31, 2020, was primarily related to a 3% decrease in our production and savings associated with midstream contract rejections and renegotiations through the bankruptcy process. The decrease in per unit transportation, gathering, processing and compression when comparing the Combined Period to the year ended December 31, 2020, was primarily related to midstream contract rejections and renegotiations through the bankruptcy process.

Depreciation, Depletion and Amortization (in thousands)

	Successor	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020
Depreciation, depletion and amortization of oil and gas properties	$ 159,518	$ 60,831	$ 229,703
Depreciation, depletion and amortization of other property and equipment	$ 1,395	$ 1,933	$ 10,041
Total depreciation, depletion and amortization	$ 160,913	$ 62,764	$ 239,744
Total depreciation, depletion and amortization per Mcfe	$ 0.69	$ 0.47	$ 0.63

The decrease in depreciation, depletion and amortization of our oil and gas properties is primarily the result of impairments taken in 2020 which decreased the depletion rate, partially offset by an increase in the depletion rate for the Successor Period as a result of the fresh start valuations on our oil and gas properties. See Note 3 of our consolidated financial statements for more information on fresh start adjustments.

Impairment of Oil and Gas Properties. During the Successor Period, we had $117.8 million oil and natural gas properties impairment charges, compared to $1.4 billion impairment charges of oil and gas properties in 2020. Upon the application of fresh start accounting, the value of our oil and natural gas properties was determined using forward strip oil and natural gas prices as of the emergence date. These prices were higher than the 12-month weighted average prices used in the full cost ceiling limitation at June 30, 2021, which led to the Successor Period impairment charge.

Impairment of Other Property and Equipment. We recognized a $14.6 million impairment charge on the Company's corporate headquarters during the Predecessor Period as a result in a change in expected future use.

General and Administrative Expenses (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
General and administrative expenses, gross	$ 53,711	$ 32,152	$ 85,863	$ 95,904
Reimbursed from third parties	(7,373)	(4,957)	(12,330)	(11,567)
Capitalized general and administrative expenses	(11,873)	(8,020)	(19,893)	(25,008)
General and administrative expenses, net	$ 34,465	$ 19,175	$ 53,640	$ 59,329
General and administrative expenses, net per Mcfe	$ 0.15	$ 0.14	$ 0.15	$ 0.16

The decrease in total general and administrative expenses during the Combined Period compared to the year ended December 31, 2020, was primarily driven by retention payments made in 2020 and our continued focus on workforce and leadership structure to ensure our cost structure is competitive with industry peers.

Restructuring and Liability Management Expenses. During the Successor Period and the year ended December 31, 2020, we incurred restructuring charges related to reductions in workforce as we continued to align our workforce and leadership structure to our current operating environment. Additionally, during the year ended December 31, 2020, we incurred liability management charges related to legal advisors engaged to assist with the evaluation of a range of liability management alternatives prior to our ultimate Chapter 11 filing.

The following table summarizes the restructuring and liability management charges incurred (in thousands):

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Reduction in workforce	$ 2,858	$ —	$ 2,858	$ 1,460
Liability management	—	—	—	29,387
Total restructuring and liability management	$ 2,858	$ —	$ 2,858	$ 30,847

Accretion Expense. Accretion expense decreased to $2.4 million for the Combined Period, from $3.1 million for the year ended December 31, 2020. The decrease in accretion expense stems primarily from a decrease in our asset retirement obligation as a result of fresh start adjustments upon emergence. See Note 3 of our consolidated financial statements for more information on fresh start adjustments.

Interest Expense (in thousands)

	Successor	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020
Interest expense on Predecessor Senior Notes	$ —	$ —	$ 98,528
Interest expense on Pre-Petition Revolving Credit Facility	—	2,044	14,224
Interest expense on Building Loan and other	560	(989)	1,861
Capitalized interest	(198)	—	(907)
Amortization of loan costs	1,663	—	5,563
Interest on DIP Credit Facility	—	3,104	810
Interest on Exit Facility	5,810	—	—
Interest on First-Out Term Loan	3,564	—	—
Interest on Successor Senior Notes	27,476	—	—
Interest on New Credit Facility	1,978	—	—
Total interest expense	$ 40,853	$ 4,159	$ 120,079
Interest expense per Mcfe	$ 0.18	$ 0.03	$ 0.32

The decrease in interest expense during the Successor Period compared to the year ended December 31, 2020, was due the changes in our debt structure upon emergence from Chapter 11.

Loss (Gain) on Debt Extinguishment. During the Successor Period, the Company recognized a loss of $3.0 million associated with the extinguishment of capitalized commitment fees related to the Exit Credit Facility as discussed in Note 6 of our consolidated financial statements. During 2020, we repurchased in the open market $73.3 million aggregate principal amount of our Predecessor Senior Notes for $22.8 million in cash and recognized a $49.6 million gain on debt extinguishment.

Equity Investments (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Loss from equity method investments, net	$ —	$ 342	$ 342	$ 11,055

We, through our wholly owned subsidiary Grizzly Holdings, own an approximate 24.5% interest in Grizzly, a Canadian unlimited liability company. Effective as of the Emergence Date, we evaluated our investment in Grizzly and determined that we no longer have the ability to exercise significant influence over operating and financial policies of Grizzly Holdings. As such, we discontinued the equity method of accounting for our investment in Grizzly and we will use our previous carrying value of zero as our initial basis and will subsequently measure at fair value while recording any changes in fair value in earnings.

During the year ended December 31, 2020, our share of net loss from Mammoth Energy Services, Inc. was in excess of the carrying value of our investment, which reduced our investment to zero. Our carrying value remained at zero through the Predecessor Period until the use of Mammoth Shares to settle Class 4A claims at the Emergence Date. See Note 15 of our consolidated financial statements for further discussion on our equity investments.

Reorganization Items, Net. The following table summarizes the components in reorganization items, net included in our consolidated statements of operations for the Combined Period and the year ended December 31, 2020 (in thousands):

	Successor	Predecessor	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020
Legal and professional advisory fees	$ —	$ (81,565)	$ (24,905)
Adjustment for allowed claims	—	—	(104,943)
Net gain on liabilities subject to compromise	—	575,182	—
Fresh start adjustments, net	—	(160,756)	—
Elimination of predecessor accumulated other comprehensive income	—	(40,430)	—
Debt issuance costs	—	(3,150)	(21,956)
Other items, net	—	(22,383)	(555)
Reorganization items, net	$ —	$ 266,898	$ (152,359)

We do not expect to incur any reorganization costs in 2022. See Note 3 of our consolidated financial statements for further discussion of the components of reorganization items, net.

Other Expense, Net (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Other expense, net	$ 13,049	$ 1,713	$ 14,762	$ 21,324

The decrease in other expense for the Combined Period compared to the year ended December 31, 2020 is primarily the result of a $16.6 million loss on the change in fair value of our contingent consideration agreement related to the sale of our SCOOP water infrastructure assets to a third-party water service provider during the year ended December 31, 2020.

Income Taxes (in thousands)

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Income tax (benefit) expense	$ (39)	$ (7,968)	$ (8,007)	$ 7,290

For the Predecessor Period, we had an effective tax rate of (3.3)% and an income tax benefit of $8.0 million. The tax benefit is entirely attributable to an Oklahoma refund claim associated with an examination relating to historical tax returns. The effective tax rate differs from the statutory tax rate due to the Company's valuation allowance position and the permanent adjustments relating to the Chapter 11 Emergence. For the Successor Period, we had an effective tax rate of 0.03% and tax expense of $39 thousand. The tax expense is entirely attributable to the Oklahoma refund claim that was filed during the third quarter, resulting in an adjustment to the benefit recorded during the Predecessor Period. We did not record any additional income tax expense for the Successor Period as a result of maintaining a full valuation allowance against our net deferred tax asset. The change in income tax expense relative to 2020 is primarily the result of the recognition of a valuation allowance against a state deferred tax asset.

Liquidity and Capital Resources

Overview. We strive to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility, fund our development projects, operations and capital expenditures and return capital to shareholders. We utilize derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company's cash flows. Historically, we have generally funded our operations, planned capital expenditures and any debt or share repurchases with cash flow from our operating activities, cash on hand, borrowings under our revolving credit facility and issuances of equity and debt securities.

For the Successor Period, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations, and our primary uses of cash have been for net principal payments under the New Credit Facility and the development of our oil and natural gas properties. Historically, our primary sources of capital funding and liquidity have been our operating cash flow, borrowings under our credit agreements and issuances of equity and debt securities. Our ability to issue additional indebtedness, dispose of assets or access the capital markets was substantially limited or nonexistent during the Chapter 11 Cases and required court approval in most instances. Accordingly, our liquidity in the Predecessor periods depended mainly on cash generated from operating activities and available funds under the DIP Credit Facility in the 2021 Predecessor Period and Pre-Petition Revolving Credit Facility in the 2020 Predecessor Period.

We believe our annual free cash flow generation, borrowing capacity under the New Credit Facility and cash on hand will provide sufficient liquidity to fund our operations, capital expenditures, interest expense, debt repayments and any return of capital to shareholders authorized by the Board, during the next 12 months.

To the extent actual operating results, realized commodity prices or uses of cash differ from our assumptions, our liquidity could be adversely affected. See Note 6 of our consolidated financial statements for further discussion of our debt obligations, including principal and carrying amounts of our notes.

As of December 31, 2021, we had a cash balance of $3.3 million compared to $89.9 million as of December 31, 2020, and a net working capital deficit of $361.4 million as of December 31, 2021, compared to a net working capital deficit of $100.5 million as of December 31, 2020. As of December 31, 2021, our working capital deficit includes no debt due in the next 12 months. Our total principal debt as of December 31, 2021, was $714.0 million compared to $2.3 billion as of December 31, 2020. See Note 6 of our consolidated financial statements for further discussion of our debt obligations, including principal and carrying amounts of our notes.

As of February 25, 2022, we had $7.1 million of cash and cash equivalents, zero borrowings under our New Credit Facility, $109.8 million of letters of credit outstanding, and $550 million of outstanding 2026 Notes.

Post-Emergence Debt. On the Emergence Date, pursuant to the terms of the Plan, we entered into a reserve-based credit agreement providing for the Exit Credit Facility, which featured an initial borrowing base of $580.0 million. The Exit Credit Facility consisted of the Exit Facility and the First-Out Term Loan. In October 2021, we amended and refinanced the Exit Credit Facility with the New Credit Facility.

As discussed in Note 6 of our consolidated financial statements, on October 14, 2021, we entered into the Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and various lender parties. The New Credit Facility provides for an aggregate maximum principal amount of up to $1.5 billion, an initial borrowing base of $850.0 million and an initial aggregate elected commitment amount of $700.0 million. The credit agreement also provides for a $175.0 million sublimit of the aggregate commitments that is available for the issuance of letters of credit.

Additionally, on the Emergence Date, pursuant to the terms of the Plan, we issued $550 million aggregate principal amount of our Successor Senior Notes.

The Successor Senior Notes are guaranteed on a senior unsecured basis by each of the Company's subsidiaries that guarantee the New Credit Facility.

See Note 6 of our consolidated financial statements for additional discussion of our post-emergence debt.

Preferred Dividends. As discussed in Note 7 of our consolidated financial statements, holders of New Preferred Stock are entitled to receive cumulative quarterly dividends at a rate of 10% per annum of the liquidation preference with respect to cash dividends and 15% per annum of the liquidation preference with respect to dividends paid in kind as additional shares of New Preferred Stock (“PIK Dividends”).

Supplemental Guarantor Financial Information. The Successor Senior Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee our New Credit Facility or certain other debt (the “Guarantors”). The Senior Notes are not guaranteed by Grizzly Holdings or Mule Sky, LLC (the “Non-Guarantors”). The Guarantors are 100% owned by the Parent, and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Successor Senior Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our amended and restated credit agreement) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Successor Senior Notes.

SEC Regulation S-X Rule 13-01 requires the presentation of "Summarized Financial Information" to replace the "Condensed Consolidating Financial Information" required under Rule 3-10. Rule 13-01 allows the omission of Summarized Financial Information if assets, liabilities and results of operations of the Guarantors are not materially different than the corresponding amounts presented in our consolidated financial statements. The Parent and Guarantor subsidiaries comprise our material operations. Therefore, we concluded that the presentation of the Summarized Financial Information is not required as our Summarized Financial Information of the Guarantors is not materially different from our consolidated financial statements.

Derivatives and Hedging Activities. Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered 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 total revenue we will receive. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for further discussion on the impact of commodity price risk on our financial position. Additionally, see Note 13 of our consolidated financial statements for further discussion of derivatives and hedging activities. Subsequent to December 31, 2021 and as of February 25, 2022, we entered into the following natural gas, oil, and NGL derivative contracts:

Period	Type of Derivative Instrument	Index	Daily Volume(1)	Weighted Average Price
January 2023 - December 2023	Swaps	NYMEX WTI	1,000	$69.78
January 2023 - December 2023	Swaps	NYMEX Henry Hub	40,082	$3.56
January 2023 - December 2023	Swaps	Mont Belvieu C3	1,000	$36.33
January 2023 - December 2023	Basis Swaps	Rex Zone 3	10,000	$(0.20)

(1) Volumes for gas instruments are presented in MMBtu while oil and NGL volumes are presented in Bbls.

*Contractual and Commercial Obligations***.** The following table sets forth our contractual and commercial obligations at December 31, 2021 (in thousands):

	Payment due by period				
Contractual Obligations	**Total**	**2022**	**2023-2024**	**2025-2026**	**2027 and Thereafter**
Long-term debt(1):					
Principal	$ 714,000	$ —	$ —	$ 714,000	$ —
Interest	192,500	44,000	88,000	60,500	—
Firm transportation and gathering contracts(2)	1,778,093	225,200	438,514	268,131	846,248
Operating lease liabilities(3)	322	182	140	—	—
Total contractual cash obligations(4)	$ 2,684,915	$ 269,382	$ 526,654	$ 1,042,631	$ 846,248

(1) The maturities of our debt obligations and associated interest reflect their original expiration dates and do not reflect any acceleration due to any events of default pertaining to these obligations. See Note 6 of our consolidated financial statements for a description of our long-term debt.
(2) Our commitments under our firm transportation and gathering contracts do not reflect contracts recently rejected or in the process of being rejected as discussed in the Litigation and Regulatory Proceedings section in Note 19 of our consolidated financial statements. See Note 18 of our consolidated financial statements for further discussion of our firm transportation and gathering commitments.
(3) See Note 10 of our consolidated financial statements for a description of our operating lease liabilities.
(4) This table does not include derivative liabilities or the estimated discounted cost for future abandonment of oil and natural gas properties. See Notes 13 and 5 of our consolidated financial statements, respectively.

Off-balance Sheet Arrangements. We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2021, our material off-balance sheet arrangements and transactions include $122.1 million in letters of credit outstanding against our revolving credit facility and $32.7 million in surety bonds issued. Both the letters of credit and surety bonds are being used as financial assurance on certain firm transportation agreements. The Company expects to enter into similar contractual arrangements in the future in order to support the Company's business plans. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources.

Capital Expenditures. Our capital expenditures have been primarily for the acquisition and development of oil and gas properties. Our capital investment strategy is focused on prudently developing our existing properties in an effort to generate sustainable cash flow considering current and forecasted commodity prices.

Our 2022 drilling and completion capital expenditure program is expected to be in a range of $320 million to $360 million. In addition, we expect to spend approximately $20 million on leasehold and land expenses, primarily associated with lease extensions in the Utica. The midpoint of the 2022 range of capital expenditures is approximately 23% higher than the $292.9 million spent in 2021, primarily due to inflation and our efforts to run a more continuous development program in the Utica, allowing for increased operational efficiencies and opportunities for incremental cost reductions.

Commodity Price Risk. The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. During 2021, WTI prices ranged from $47.47 to $85.64 per barrel and the Henry Hub spot market price of natural gas ranged from $2.43 to $23.86 per MMBtu. During 2020, WTI prices ranged from $(36.98) to $63.27 per barrel and the Henry Hub spot market price of natural gas ranged from $1.33 to $3.14 per MMBtu. If the prices of oil and natural gas decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in commodity prices and/or our reserves could also negatively impact the borrowing base under our revolving credit facility, which could limit our liquidity and ability to fund development activities.

See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" for further information regarding our open derivative instruments at December 31, 2021.

Cash Flow from Operating Activities. Net cash flow provided by operating activities was $465.1 million for the Combined Period as compared to $95.3 million for the year ended December 31, 2020. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to an 88% increase in net natural gas, oil and NGL sales excluding the impact of derivatives.

Divestitures. During the Successor Period and 2020, we divested certain water infrastructure assets and non-core assets and interests in operated and non-operated oil and natural gas properties for approximately cash proceeds $4.3 million and $51.0 million, respectively. Proceeds from these transactions were primarily used to repay debt and fund our development program. See Note 4 of our consolidated financial statements for further discussion.

Uses of Funds. The following table presents the uses of our cash and cash equivalents for the Successor Period, Predecessor Period, and year ended December 31, 2020 (in thousands):

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2021	Year Ended December 31, 2020
Oil and Natural Gas Property Cash Expenditures:				
Drilling and completion costs	$ 183,333	$ 94,128	$ 277,461	$ 321,811
Leasehold acquisitions	13,022	2,752	15,774	18,135
Other	10,758	5,450	16,208	27,341
Total oil and natural gas property expenditures	$ 207,113	$ 102,330	$ 309,443	$ 367,287
Other Uses of Cash and Cash Equivalents:				
Principal payments on Pre-Petition Revolving Credit Facility, net	$ —	$ 292,911	$ 292,911	$ —
Principal payments on DIP credit facility	—	157,500	157,500	—
Principal payments on Exit Credit Facility, net	302,751	—	302,751	—
Cash paid to repurchase senior notes	—	—	—	22,827
DIP Credit Facility Financing Fees	—	—	—	2,988
Debt issuance costs and loan commitment fees	8,783	7,100	15,883	738
Other	1,753	397	2,150	1,034
Total other uses of cash and cash equivalents	$ 313,287	$ 457,908	$ 771,195	$ 27,587
Total uses of cash and cash equivalents	$ 520,400	$ 560,238	$ 1,080,638	$ 394,874

Drilling and Completion Costs. During the Combined Period, we spud 20 gross (19 net) wells and commenced sales from 17 gross and net wells in the Utica for a total cost of approximately $191.5 million.

During the Combined Period, we spud 9 gross (7.7 net) and commenced sales from 11 gross (9.4 net) wells in the SCOOP for a total cost of approximately $83.5 million. In addition, 25 gross (1.77 net) wells were spud and 21 gross (0.05 net) wells were turned to sales by other operators on our SCOOP acreage during 2021 for a total cost to us of approximately $6.0 million.

Drilling and completion costs presented in this section reflect incurred costs while drilling and completion costs presented above in *Uses of Funds* section reflect cash payments for drilling and completions.

Critical Accounting Policies and 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 we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Reorganization and Fresh Start Accounting. The Company applied FASB ASC Topic 852 - *Reorganizations* ("ASC 852") in preparing the consolidated financial statements, which specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements included distinguishing transactions associated with the reorganization separate from activities related to the ongoing operations of the business. Accordingly, pre-petition liabilities that may be impacted by the Chapter 11 proceedings were classified as liabilities subject to compromise on the consolidated balance sheet as of December 31, 2020. Additionally, certain expenses, realized gains and losses and provisions for losses that were realized or incurred during the Chapter 11 Cases, including adjustments to the carrying value of certain indebtedness were recorded as reorganization items, net in the consolidated statements of operations for the year ended December 31, 2020 and the Predecessor Period.

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. Refer to Note 2 and Note 3 of our consolidated financial statements for more information on the events of the bankruptcy proceedings as well as the accounting and reporting impacts of the reorganization.

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test.

Two primary factors impacting this test are reserve estimates and the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2021. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. During the Successor Period, we recorded impairments of our oil and natural gas properties in the amount of $117.8 million compared to $1.4 billion during the year ended December 31, 2020. See Oil and Natural Gas Properties in Note 1 of our consolidated financial statements for further information on the full cost method of accounting.

Oil, Natural Gas and NGL Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions.

Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See Note 20 of our consolidated financial statements for further information.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Quarterly, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2021, a valuation allowance of $907.4 million had been established to fully offset our net deferred tax asset on our accompanying consolidated balance sheet.

Revenue Recognition. We derive almost all of our revenue from the sale of natural gas, crude oil and NGL produced from our oil and natural gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. Historically, our actual payments received have not significantly deviated from our accruals.

Derivative Instruments. We seek to reduce our exposure to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, costless collars and various types of option contracts. All derivative instruments are recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk. Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL, which have been historically volatile and are even more volatile as a result of COVID-19 and decisions of the Organization of Petroleum Exporting Countries and other high oil-exporting countries ("OPEC+") discussed in this Form 10-K. To mitigate a portion of our exposure to adverse price changes, we have entered 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.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas, oil and NGL futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends. Executive management is involved in all risk management activities and the board of directors reviews our derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading.

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility.

We determine the notional volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate this risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are identical to those we review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month specified in the original contract.

We have determined 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. 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 16 of our consolidated financial statements for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2021, our natural gas derivative instruments consistent 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.
- *Basis 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.
- *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.
- *Costless Collars*: Each two-way price collar has a set floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, the Company will cash-settle the difference with the counterparty.

Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or commodities prices increase. At December 31, 2021, we had a net liability derivative position of $402.0 million as compared to a net liability derivative position of $20.8 million as of December 31, 2020. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have increased our liability by approximately $182.7 million, while a 10% decrease in underlying commodity prices would have decreased our liability by approximately $171.0 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument. For more information regarding the Company's commodity derivative transactions, refer to Note13 of our consolidated financial statements.

Counterparty Credit Risk. The Company routinely monitors and manages its exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. The Company's commodity derivative contract counterparties are typically financial institutions with investment-grade credit ratings. The Company enters into International Swap Dealers Association Master Agreements (ISDA) with each of its derivative counterparties prior to executing derivative contracts. The terms of the ISDA provide, among other things, the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or counterparty to a derivative contract.

Interest Rate Risk. Our New Credit Facility is structured under floating rate terms, as advances under these facilities may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the United States or, if the eurodollar rates are elected, the eurodollar rates. At December 31, 2021, we had $164.0 million in borrowings outstanding under our revolving credit facility which bore interest at the weighted average rate of 3.19%. A 1% increase in the average interest rate would increase interest expense by approximately $2 million based on outstanding borrowings under our revolving credit facility at December 31, 2021. As of December 31, 2021, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2021 (Successor) and 2020 (Predecessor), the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit) and cash flows for the period from May 18, 2021 through December 31, 2021 (Successor), the period from January 1, 2021 through May 17, 2021 (Predecessor) and the years ended December 31, 2020 and 2019 (Predecessor), and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 (Successor) and 2020 (Predecessor), and the results of itsoperations and its cash flows for the period from May 18, 2021 through December 31, 2021 (Successor), the period from January 1, 2021 through May 17, 2021 (Predecessor) and for the years ended December 31, 2020 and 2019 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 1, 2022 expressed an unqualified opinion.

Emergence from bankruptcy
As discussed in Note 1 to the financial statements, the United States Bankruptcy Court for the District of Delaware entered an order confirming the plan for reorganization on April 28, 2021, and the Company emerged from bankruptcy on May 17, 2021. Accordingly, the accompanying financial statements have been prepared in conformity with FASB Accounting Standards Codification 852, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods, as described in Note 3.

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

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

Depletion, depreciation and amortization expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves

As described further in Note 1 to the financial statements, the Company uses the full cost method of accounting for oil and gas operations. This accounting method requires management to make estimates of proved reserves and related future net cash flows to compute and record depletion, depreciation and amortization, as well as to assess potential impairment of oil and gas properties (the full cost ceiling test). To estimate the volume of proved oil and gas reserve quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company’s development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management’s judgments and estimates regarding the financial performance of wells associated with those proved reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of depletion, depreciation and amortization expense and potential ceiling test impairment assessments. We identified the estimation of proved reserves as it relates to the recognition of depletion, depreciation and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company’s proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and/or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others:

- We tested the design and operating effectiveness of internal controls relating to management’s estimation of proved reserves for the purpose of estimating depletion, depreciation and amortization expense and assessing the Company’s oil and gas properties for potential ceiling test impairment.

- We evaluated the independence, objectivity, and professional qualifications of the Company’s reserves specialist, made inquiries of those reservoir engineers regarding the process followed and judgements made to estimate the Company’s proved reserve volumes and read the report prepared by the Company’s reserve specialist.

- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions that are derived from the Company’s accounting records, such as historical pricing differentials, operating costs, estimated future development costs, and ownership interest. We tested management’s process for determining the assumptions, including examining the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management’s assumptions as follows:

    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for pricing differentials, where applicable;
    - Tested the model used to estimate the operating costs at year end and compared to historical operating costs;
    - Tested the model used to determine the future development costs and compared estimated future development costs used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
    - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
    - Evaluated the Company’s evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company’s ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year’s reserve report.

Valuation of oil and natural gas properties in association with fresh start accounting

As described further in Notes 1, 2 and 3 to the financial statements, on May 17, 2021, the Company emerged from Chapter 11 bankruptcy. In connection with its emergence, the Company qualified for and applied fresh start accounting. Management calculated a reorganization value, which represents the estimated fair value of the Successor's assets before considering liabilities and allocated the value to its individual assets based on their estimated fair values with the assistance of third-party valuation advisors. We identified the valuation of oil and natural gas properties associated with fresh start accounting to be a critical audit matter.

The principal considerations for our determination that the valuation of oil and natural gas properties associated with fresh start accounting are that there were significant management judgements made with respect to assumptions used to estimate the fair value of the oil and natural gas properties, including the cash flows related to recoverable reserves, production rates, future operating and development costs, future commodity prices, discount rate and risk adjustments. These inputs and assumptions involved increased auditor subjectivity in evaluating the appropriateness of those assumptions.

Our audit procedures related to the valuation of oil and natural gas properties in association with fresh start accounting included the following, among others.

- We tested the design and operating effectiveness of controls for management's review of the significant assumptions used in the third-party valuation report and valuation methodologies applied.
- We evaluated the qualifications and objectivity of the Company’s third-party valuation advisors.
- With the assistance of valuation professionals with specialized skills and knowledge, we evaluated the methodology used by management to develop oil and natural gas reserve quantities and discounted future net cash flows and key assumptions including the risk adjustment factors applied to reserves, the discount rate and income tax rate.
- We performed procedures similar to those described above on the estimated oil and gas reserves that were a key input to the valuation of proved and unproved oil and natural gas properties.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2005.

Oklahoma City, Oklahoma
March 1, 2022

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands)

Assets	Successor December 31, 2021	Predecessor December 31, 2020
Current assets:		
Cash and cash equivalents	$ 3,260	$ 89,861
Accounts receivable—oil and natural gas sales	232,854	119,879
Accounts receivable—joint interest and other	20,383	12,200
Prepaid expenses and other current assets	12,359	160,664
Short-term derivative instruments	4,695	27,146
Total current assets	273,551	409,750
Property and equipment:		
Oil and natural gas properties, full-cost method		
Proved oil and natural gas properties	1,917,833	9,359,866
Unproved properties	211,007	1,457,043
Other property and equipment	5,329	88,538
Total property and equipment	2,134,169	10,905,447
Less: accumulated depletion, depreciation and amortization	(278,341)	(8,819,178)
Total property and equipment, net	1,855,828	2,086,269
Other assets:		
Equity investments	—	24,816
Long-term derivative instruments	18,664	322
Operating lease assets	322	342
Other assets	19,867	18,372
Total other assets	38,853	43,852
Total assets	$ 2,168,232	$ 2,539,871

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS–CONTINUED
(In thousands)

Liabilities, Mezzanine Equity and Stockholders' Equity (Deficit)	Successor December 31, 2021	Predecessor December 31, 2020
Current liabilities:		
Accounts payable and accrued liabilities	$ 394,011	$ 244,903
Short-term derivative instruments	240,735	11,641
Current portion of operating lease liabilities	182	—
Current maturities of long-term debt	—	253,743
Total current liabilities	634,928	510,287
Non-current liabilities:		
Long-term derivative instruments	184,580	36,604
Asset retirement obligation	28,264	—
Non-current operating lease liabilities	140	—
Long-term debt, net of current maturities	712,946	—
Total non-current liabilities	925,930	36,604
Liabilities subject to compromise	—	2,293,480
Total liabilities	$ 1,560,858	$ 2,840,371
Commitments and contingencies (Notes 18 and 19)		
Mezzanine Equity:		
New Preferred Stock - $0.0001 par value, 110 thousand shares authorized, 57.9 thousand issued and outstanding at December 31, 2021	57,896	—
Stockholders' Equity (Deficit):		
Predecessor common stock - $0.01 par value, 200.0 million shares authorized, 160.8 million issued and outstanding at December 31, 2020	—	1,607
Predecessor accumulated other comprehensive loss	—	(43,000)
New Common Stock - $0.0001 par value, 42.0 million shares authorized, 20.6 million issued and outstanding at December 31, 2021	2	—
Additional paid-in capital	692,521	4,213,752
New Common Stock held in reserve, 938 thousand shares	(30,216)	—
Accumulated deficit	(112,829)	(4,472,859)
Total stockholders' equity (deficit)	$ 549,478	$ (300,500)
Total liabilities, mezzanine equity and stockholders' equity (deficit)	$ 2,168,232	$ 2,539,871

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
REVENUES:				
Natural gas sales	$ 906,096	$ 344,390	$ 671,535	$ 1,135,381
Oil and condensate sales	81,347	29,106	62,902	117,937
Natural gas liquid sales	105,141	36,780	66,814	101,448
Net (loss) gain on natural gas, oil and NGL derivatives	(556,819)	(137,239)	65,291	208,360
Total Revenues	535,765	273,037	866,542	1,563,126
OPERATING EXPENSES:				
Lease operating expenses	32,172	19,524	54,235	73,496
Taxes other than income	30,243	12,349	28,509	40,510
Transportation, gathering, processing and compression	212,013	161,086	456,318	508,843
Depreciation, depletion and amortization	160,913	62,764	239,744	550,108
Impairment of oil and natural gas properties	117,813	—	1,357,099	2,039,770
Impairment of other property and equipment	—	14,568	—	—
General and administrative expenses	34,465	19,175	59,329	45,542
Restructuring and liability management expenses	2,858	—	30,847	4,611
Accretion expense	1,214	1,229	3,066	3,939
Total Operating Expenses	591,691	290,695	2,229,147	3,266,819
INCOME (LOSS) FROM OPERATIONS	(55,926)	(17,658)	(1,362,605)	(1,703,693)
OTHER EXPENSE (INCOME):				
Interest expense	40,853	4,159	120,079	141,786
Loss (Gain) on debt extinguishment	3,040	—	(49,579)	(48,630)
Loss from equity method investments, net	—	342	11,055	210,148
Reorganization items, net	—	(266,898)	152,359	—
Other expense	13,049	1,713	21,324	2,924
Total Other Expense	56,942	(260,684)	255,238	306,228
INCOME (LOSS) BEFORE INCOME TAXES	(112,868)	243,026	(1,617,843)	(2,009,921)
Income Tax (Benefit) Expense	(39)	(7,968)	7,290	(7,563)
NET (LOSS) INCOME	$ (112,829)	$ 250,994	$ (1,625,133)	$ (2,002,358)
Dividends on New Preferred Stock	$ (4,573)	$ —	$ —	$ —
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (117,402)	$ 250,994	$ (1,625,133)	$ (2,002,358)
NET (LOSS) INCOME PER COMMON SHARE:				
Basic	$ (5.71)	$ 1.56	$ (10.14)	$ (12.49)
Diluted	$ (5.71)	$ 1.56	$ (10.14)	$ (12.49)
Weighted average common shares outstanding—Basic	20,545	160,834	160,231	160,341
Weighted average common shares outstanding—Diluted	20,545	160,834	160,231	160,341

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(In thousands)

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Net (loss) income	$ (112,829)	$ 250,994	$ (1,625,133)	$ (2,002,358)
Foreign currency translation adjustment	—	2,570	3,833	9,193
Other comprehensive income	—	2,570	3,833	9,193
Comprehensive (loss) income	$ (112,829)	$ 253,564	$ (1,621,300)	$ (1,993,165)

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY(DEFICIT)
(In thousands)

	Common Stock		Common Stock Held in Reserve		Paid-in Capital	Accumulated Other Comprehensive (Loss) Income	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount				
Balance at January 1, 2019 (Predecessor)	162,986	$ 1,630	—	$ —	$ 4,227,532	$ (56,026)	$ (845,368)	$ 3,327,768
Net loss	—	—	—	—	—	—	(2,002,358)	(2,002,358)
Other comprehensive income	—	—	—	—	—	9,193	—	9,193
Stock compensation	—	—	—	—	10,677	—	—	10,677
Shares repurchased	(3,951)	(40)	—	—	(30,648)	—	—	(30,688)
Issuance of restricted stock	676	7	—	—	(7)	—	—	—
Balance at December 31, 2019 (Predecessor)	159,711	$ 1,597	—	$ —	$ 4,207,554	$ (46,833)	$ (2,847,726)	$ 1,314,592
Net loss	—	—	—	—	—	—	(1,625,133)	(1,625,133)
Other comprehensive income	—	—	—	—	—	3,833	—	3,833
Stock compensation	—	—	—	—	6,444	—	—	6,444
Shares repurchased	(243)	(3)	—	—	(233)	—	—	(236)
Issuance of restricted stock	1,294	13	—	—	(13)	—	—	—
Balance at December 31, 2020 (Predecessor)	160,762	$ 1,607	—	$ —	$ 4,213,752	$ (43,000)	$ (4,472,859)	$ (300,500)

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' (DEFICIT) EQUITY–CONTINUED
(In thousands)

	Common Stock		Common Stock Held in Reserve		Paid-in Capital	Accumulated Other Comprehensive (Loss) Income	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount				
Balance at January 1, 2021 (Predecessor)	160,762	$ 1,607	—	$ —	$ 4,213,752	$ (43,000)	$ (4,472,859)	$ (300,500)
Net income	—	—	—	—	—	—	250,994	250,994
Other comprehensive income	—	—	—	—	—	2,570	—	2,570
Stock compensation	—	—	—	—	6,514	—	—	6,514
Shares repurchased	(96)	(1)	—	—	(7)	—	—	(8)
Issuance of restricted stock	228	3	—	—	(2)	—	—	1
Accumulated other comprehensive income extinguishment	—	—	—	—	—	40,430	—	40,430
Cancellation of predecessor equity	(160,894)	(1,609)	—	—	(4,220,256)	—	4,221,865	—
Issuance of New Common Stock	21,525	2	—	—	693,773	—	—	693,775
Shares of New Common Stock held in reserve	—	—	(1,679)	(54,109)	—	—	—	(54,109)
Balance at May 17, 2021 (Predecessor)	21,525	$ 2	(1,679)	$ (54,109)	$ 693,774	$ —	$ —	$ 639,667
Balance at May 18, 2021 (Successor)	21,525	$ 2	(1,679)	$ (54,109)	$ 693,774	$ —	$ —	$ 639,667
Net loss	—	—	—	—	—	—	(112,829)	(112,829)
Release of New Common Stock held in reserve	—	—	741	23,893	—	—	—	23,893
Conversion of New Preferred Stock	12	—	—	—	171	—	—	171
Dividends on New Preferred Stock	—	—	—	—	(4,573)	—	—	(4,573)
Stock compensation	—	—	—	—	3,149	—	—	3,149
Balance at December 31, 2021 (Successor)	21,537	$ 2	(938)	$ (30,216)	$ 692,521	$ —	$ (112,829)	$ 549,478

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash flows from operating activities:				
Net (loss) income	$ (112,829)	$ 250,994	$ (1,625,133)	$ (2,002,358)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation and amortization	160,913	62,764	239,744	550,108
Impairment of oil and natural gas properties	117,813	—	1,357,099	2,039,770
Impairment of other property and equipment	—	14,568	—	—
Loss from equity investments	—	342	11,055	210,289
Gain on sale of equity method investments	—	—	—	(220)
Distributions from equity method investments	—	—	—	2,457
Loss (Gain) on debt extinguishment	3,040	—	(49,579)	(48,630)
Net loss (gain) on derivative instruments	556,819	137,239	(65,291)	(208,360)
Net cash (payments) receipts on settled derivative instruments	(322,857)	(3,361)	159,394	123,130
Non-cash reorganization items, net	—	(446,012)	21,956	—
Deferred income tax expense	—	—	7,290	(7,563)
Other, net	3,130	1,727	31,984	15,178
Changes in operating assets and liabilities, net	(113,044)	153,894	6,785	50,192
Net cash provided by operating activities	$ 292,985	$ 172,155	$ 95,304	$ 723,993
Cash flows from investing activities:				
Additions to oil and natural gas properties	$ (207,113)	$ (102,330)	$ (367,287)	$ (720,057)
Proceeds from sale of oil and natural gas properties	4,339	15	50,971	48,527
Other, net	2,669	4,484	1,729	(3,241)
Net cash used in investing activities	$ (200,105)	$ (97,831)	$ (314,587)	$ (674,771)
Cash flows from financing activities:				
Principal payments on Pre-Petition Revolving Credit Facility	$ —	$ (318,961)	$ (383,290)	$ (877,000)
Borrowings on Pre-Petition Revolving Credit Facility	—	26,050	713,701	952,000
Borrowings on Exit Credit Facility	406,277	302,751	—	—
Principal payments on Exit Credit Facility	(709,028)	—	—	—
Principal payments on DIP credit facility	—	(157,500)	(90,000)	—
Borrowings on DIP Credit facility	—	—	90,000	—
Principal payments on New Credit Facility	(477,000)	—	—	—
Borrowings on New Credit Facility	641,000	—	—	—
Debt issuance costs and loan commitment fees	(8,783)	(7,100)	—	—
Repurchase of senior notes	—	—	(22,827)	(138,786)
Payments on Repurchase of Stock	—	—	—	(30,000)
Proceeds from issuance of New Preferred Stock	—	50,000	(2,988)	—
Other, net	(1,503)	(8)	(1,512)	(1,673)
Net cash (used in) provided by in financing activities	$ (149,037)	$ (104,768)	$ 303,084	$ (95,459)
Net (decrease) increase in cash, cash equivalents and restricted cash	$ (56,157)	$ (30,444)	$ 83,801	$ (46,237)
Cash, cash equivalents and restricted cash at beginning of period	$ 59,417	$ 89,861	$ 6,060	$ 52,297
Cash, cash equivalents and restricted cash at end of period	$ 3,260	$ 59,417	$ 89,861	$ 6,060

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Company

Gulfport Energy Corporation is an independent natural gas-weighted exploration and production company focused on the production of natural gas, crude oil and NGL in the United States. The Company's principal properties are located in Eastern Ohio targeting the Utica and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations. Gulfport filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code on November 13, 2020, and subsequently operated as a debtor-in-possession, in accordance with applicable provisions of the Bankruptcy Code, until its emergence on May 17, 2021. The Company refers to the post-emergence reorganized organization in the condensed financial statements and footnotes as the "Successor" for periods subsequent to May 17, 2021, and the pre-emergence organization as "Predecessor" for periods on or prior to May 17, 2021.

Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On the Petition Date, the Debtors filed voluntary petitions of relief under the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases were administered jointly under the caption *In re Gulfport Energy Corporation, et al.,* Case No. 20-35562 (DRJ).

The Bankruptcy Court confirmed the Plan and entered the confirmation order on April 28, 2021. The Debtors emerged from the Chapter 11 Cases on the Emergence Date. The Company's bankruptcy proceedings and related matters have been summarized below.

During the pendency of the Chapter 11 Cases, the Company continued to operate its business in the ordinary course as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted the first day relief requested by the Company that was designed primarily to mitigate the impact of the Chapter 11 Cases on its operations, vendors, suppliers, customers and employees. As a result, the Company was able to conduct normal business activities and satisfy all associated obligations for the period following the Petition Date and was 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.

Subject to certain specific exceptions under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically stayed all judicial or administrative actions against the Company 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 Emergence Date.

The Company applied FASB ASC Topic 852 -*Reorganizations* ("ASC 852") in preparing the consolidated financial statements for the period ended May 17, 2021. ASC 852 specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements include distinguishing transactions associated with the reorganization separate from activities related to the ongoing operations of the business. Accordingly, pre-petition liabilities that may be impacted by the Chapter 11 proceedings were classified as liabilities subject to compromise on the consolidated balance sheet as of December 31, 2020. Additionally, certain expenses, realized gains and losses and provisions for losses that are realized or incurred during the Chapter 11 Cases are recorded as reorganization items, net. Refer to Note 3 for more information regarding reorganization items.

In connection with the Company's emergence from bankruptcy and in accordance with ASC 852, the Company qualified for and applied fresh start accounting on the Emergence date. See Note 3 for more information regarding the application of fresh start accounting.

Risks and Uncertainties

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil, gas and NGL, which are affected by many factors outside of Gulfport's control, including changes in market supply and demand. The COVID-19 pandemic and related shut-down of various sectors of the global economy resulted in a significant reduction in global demand for natural gas and crude oil since 2020. Changes in market supply and demand are also impacted by OPEC+ production levels, weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. Field-level prices received for Gulfport's production have historically been volatile and may be subject to significant fluctuations in the future. The Company's derivative contracts serve to mitigate in part the effect of this price volatility on the Company's cash flows, and the Company has derivative contracts in place for a portion of its expected future natural gas, crude oil and NGL production. See Note 13 for further discussion of the Company's commodity derivative contracts.

Gulfport remains focused on protecting the health and well-being of its employees and the communities in which it operates while assuring the continuity of its business operations. The Company implemented preventative measures and developed corporate and field response plans to minimize unnecessary risk of exposure and prevent infection. Additionally, the Company has a crisis management team for health, safety and environmental matters and personnel issues, and has established a COVID-19 Response Team to address various impacts of the situation, as they have been developing. Gulfport has modified certain business practices (including remote working for its corporate employees and restricted employee business travel) to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization and other governmental and regulatory authorities. The Company will continue to monitor trends and governmental guidelines and will adjust plans accordingly to ensure the health and safety of its employees. As a result of its business continuity measures, the Company has not experienced significant disruptions in executing its business operations in 2021.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly-owned subsidiaries, Gulfport Energy Operating Corporation, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Westhawk Minerals LLC, Puma Resources, Inc., Gulfport Appalachia LLC, Gulfport Midstream Holdings, LLC, Gulfport MidCon, LLC and Mule Sky LLC. All intercompany balances and transactions are eliminated in consolidation.

Segments

The Company's assets and operations consist of one reportable segment. The Company has a single management team that administers all properties as a whole rather than by geographic operating area. Further, the Company measures financial performance as a single enterprise and not on an area-by-area basis.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the consolidated financial statements.

Accounts Receivable

The Company sells oil and natural gas to various purchasers and participates in drilling, completion and operation of oil and natural gas wells with joint interest owners on properties the Company operates. The related receivables are classified as accounts receivable—oil and natural gas sales and accounts receivable—joint interest and other, respectively. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. No material allowance was deemed necessary at December 31, 2021 and December 31, 2020.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Additionally, interest is capitalized on the cost of unproved oil and natural gas properties that are excluded from amortization for which exploration and development activities are in process or expected within the next 12 to 18 months.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company’s oil and natural gas revenue (only to the extent that the derivative instruments are treated as cash flow hedges for accounting purposes), and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of unproved properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash write-down is required. Ceiling test impairment can result in a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. The Company recognized a ceiling test impairment of $117.8 million in the second quarter of 2021.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties, are depleted by an equivalent units-of-production method, converting barrels to gas at the ratio of one barrel of oil to six Mcf of gas. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proved oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled approximately $211.0 million and $1.5 billion at December 31, 2021 and December 31, 2020, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities by recording a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from3 to 5 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport’s consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. As of the Emergence Date, this investment is no longer accounted for under the equity method of accounting. Under the equity method of accounting, the assets and liabilities of the Canadian investment were translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses were translated at average rates for the periods presented and equity contributions are translated at the current exchange rate in effect at the date of the contribution. In addition, until the Emergence Date, the Company had an equity investment in a U.S. company that has a subsidiary that is a Canadian entity whose functional currency is the Canadian dollar. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders’ (deficit) equity.

The following table presents the balances of the Company's cumulative translation adjustments included in accumulated other comprehensive loss, exclusive of taxes:

		(In thousands)
December 31, 2019	$	(45,484)
December 31, 2020	$	(41,651)
December 31, 2021	$	—

Net (Loss) Income per Common Share

Basic net (loss) income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net (loss) income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net (loss) income per common share are illustrated in Note 12.

Income Taxes

The amount of income taxes recorded by Gulfport requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 2016 – 2021 U.S. federal and 2016 - 2021 state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2021, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. See Note 11 for further discussion of the Company's income taxes.

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company's right to payment and (iv) transfer of legal title.

Gathering, processing and compression fees attributable to gas processing, as well as any transportation fees, including firm transportation fees, incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression in the accompanying consolidated statements of operations.

Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

The recognition of gains or losses on derivative instruments is outside the scope of ASC 606, *Revenue from Contracts with Customers* and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer, such as sales tax, use tax, value-added tax and similar taxes.

See Note 9 for additional discussion of revenue from contracts with customers.

Accounting for Stock-based Compensation

Share-based payments to employees, including grants of restricted stock units and performance vesting restricted stock units, are recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for restricted shares range between one to four years with annual vesting installments. The Company does not recognize expense based on an estimate of forfeitures, but rather recognizes the impact of forfeitures only as they occur.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and NGL production. All derivative instruments are recognized as assets or liabilities in the consolidated balance sheets, measured at fair value. The Company does not apply hedge accounting to derivative instruments. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets, the fair value determination of acquired assets and liabilities and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company’s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Supplemental cash flow and non-cash information (in thousands)

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Supplemental disclosure of cash flow information:				
Cash paid for reorganization items, net	$ 85,706	$ 87,199	$ 24,553	$ —
Interest payments	33,295	7,272	84,823	142,664
Income Tax Receipts	(9,381)	—	—	(1,794)
Changes in operating assets and liabilities:				
(Increase) decrease in accounts receivable - oil and natural gas sales	(52,143)	(60,832)	1,331	88,990
(Increase) decrease in accounts receivable - joint interest and other	(5,178)	(3,005)	36,055	(25,478)
(Decrease) increase in accounts payable and accrued liabilities	(72,912)	79,193	126,434	(19,821)
Decrease (increase) in prepaid expenses	13,559	135,471	(154,948)	5,586
Decrease (increase) in other assets	3,630	3,067	(2,087)	915
Total changes in operating assets and liabilities	$ (113,044)	$ 153,894	$ 6,785	$ 50,192
Supplemental disclosure of non-cash transactions:				
Capitalized stock-based compensation	$ 1,101	$ 930	$ 2,860	$ 5,766
Asset retirement obligation capitalized	7,964	546	2,358	6,883
Asset retirement obligation removed due to divestiture	—	—	(2,213)	(30,146)
Interest capitalized	198	—	907	3,372
Pre-petition revolver principal transfer to DIP credit facility	—	—	157,500	—
Fair value of contingent consideration asset on date of divestiture	—	—	23,090	(1,137)
Release of New Common Stock Held in Reserve	23,893	—	—	—
Foreign currency translation gain on equity method investments	—	2,570	3,833	9,193

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consisted of the following at December 31, 2021 and December 31, 2020 (in thousands):

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Accounts payable and other accrued liabilities	$ 143,938	$ 120,275
Revenue payable and suspense	180,857	124,628
Accrued contract rejection damages and shares held in reserve	69,216	—
Total accounts payable and accrued liabilities	$ 394,011	$ 244,903

Recent Adopted Accounting Pronouncements

In August 2020, the FASB issued ASU No. 2020-06,*Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging— Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity.* This new standard simplifies and adds disclosure requirements for the accounting and measurement of convertible instruments. It eliminates the treasury stock method for convertible instruments and requires application of the "if-converted" method for certain agreements. In addition, the standard eliminates the beneficial conversion and cash conversion accounting models that require separate accounting for embedded conversion features and the recognition of a debt discount and related amortization to interest expense of those embedded features.

The Company elected to early adopt this standard effective on the Emergence Date. The Company adopted the new standard using the modified retrospective approach transition method. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The consolidated financial statements for the Successor Period are presented under the new standard, while the predecessor periods and comparative periods are not adjusted and continue to be reported in accordance with the Company's historical accounting policy.

2. CHAPTER 11 EMERGENCE

As described in Note 1, on November 13, 2020, the Debtors filed the Chapter 11 Cases and the Plan, which was subsequently amended, and entered the confirmation order on April 28, 2021. The Debtors then emerged from bankruptcy upon effectiveness of the Plan on May 17, 2021. Capitalized terms used but not defined herein shall have the meaning ascribed to them in the Plan.

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 May 17, 2021:

- Shares of the Predecessor's common stock outstanding immediately prior to the Emergence Date were cancelled, and on the Emergence Date, the Company issued 19,845,780 shares of New Common Stock and 55,000 shares of New Preferred Stock, which were the result of the transactions described below. The Company also entered into a registration rights agreement and amended its articles of incorporation and bylaws for the authorization of the New Common Stock and New Preferred Stock among other corporate governance actions. See Note 7 for further discussion of the Company's post-emergence equity;
- All outstanding obligations under the Predecessor Senior Notes were cancelled;
- The Predecessor effectuated certain restructuring transactions, including entering into a plan of Merger with Gulfport Merger Sub, Inc., a newly formed, wholly owned subsidiary of Gulfport ("Merger Sub"), pursuant to which Merger Sub was merged with and into Predecessor, resulting in the Predecessor becoming a wholly owned subsidiary of Gulfport;
- The Debtors entered into a Second Amended and Restated Credit Agreement (the "Exit Credit Agreement") with the Bank of Nova Scotia as administrative agent, various lender parties and acknowledged and agreed to by certain of Gulfport's subsidiaries, as guarantors, providing for (i) a new money senior secured reserve-based revolving credit facility in an aggregate maximum principal amount of up to $1.5 billion (the "Exit Facility"); (ii) a senior secured term loan in an aggregate maximum principal amount of up to $180 million (the "First-Out Term Loan") and together with the Exit Facility (the "Exit Credit Facility"), collectively with an initial borrowing base and elected commitment amount of up to $580 million (less the amount of any term loan deemed funded by any RBL Lender that is not a Consenting RBL Lender);
- The Company entered into an indenture to issue up to $550 million aggregate principal amount of its 8.000% senior notes due 2026, dated as of May 17, 2021, by and among the Issuer, UMB Bank, National Association, as trustee, and the guarantors party thereto (such indenture, the “1145 Indenture,” and such senior notes issued thereunder, the “1145 Notes”), under section 1145 of the Bankruptcy Code (“Section 1145”). Certain eligible holders have made an election (the “4(a)(2) Election”) entitling such holders to receive senior notes issued pursuant to an indenture, dated as of May 17, 2021, by and among the Issuer, UMB Bank, National Association, as trustee, and the guarantors party thereto (such indenture, the “4(a)(2) Indenture,” and such senior notes issued thereunder, the “4(a)(2) Notes”), under Section 4(a)(2) of the Securities Act of 1933, as amended as opposed to its share of the up to $550 million aggregate principal amount of 1145 Notes. The 4(a)(2) Indenture's terms are substantially similar to the terms of the 1145 Indenture. The 1145 Indenture and the 4(a)(2) Indenture are referred to together as the "Indentures". The 1145 Notes and the 4(a)(2) Notes are collectively referred to as the "Successor Senior Notes";
- The DIP Credit Facility indefeasibly converted into the Exit Facility, and all commitments under the DIP Credit Facility terminated. Each holder of an Allowed DIP Claim received, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Allowed DIP Claim its Pro Rata share of participation in the Exit Credit Facility;
- Each holder of an Allowed Notes Claim received its pro rata share of 19,714,204 shares of New Common Stock, 54,967 shares of New Preferred Stock and New Unsecured Senior Notes;

- 1,678,755 shares of New Common Stock were issued to the Disputed Claims reserve;
- Each holder of a Class 4A Claim greater than the Convenience Claim Threshold received its pro rata share of 19,679 shares of New Common Stock (which were issued to the Unsecured Claims Distribution Trust), $10 million in cash, subject to adjustment by the Unsecured Claims Distribution Trustee, and 100% of the Mammoth Shares;
- Each holder of a Class 4B claim greater than the Convenience Claim Threshold received its pro rata share of 1,897 shares of New Common Stock, 33 shares of New Preferred Stock, the Rights Offering Subscription Rights and the Successor Senior Notes;
- Each holder of a Convenience Class Claim will share in a $3 million cash distribution pool, which the Unsecured Claims Distribution Trustee may increase by an additional $2 million by reducing the Gulfport Parent Cash Pool;
- Each intercompany claim was cancelled on the Emergence Date and holders of intercompany interests received no recovery or distribution;
- The Company conducted a Rights Offering and issued 50,000 shares of New Preferred Stock at $1,000 per share to holders of claims against the Predecessor Subsidiaries, raising $50 million in proceeds. Additionally, 5,000 shares were issued to the Back Stop Commitment counterparties in lieu of cash consideration as per the Backstop Commitment Agreement; and
- The Company adopted the Gulfport Energy Corporation 2021 Stock Incentive Plan (the "Incentive Plan") effective on the Emergence Date and reserved 2,828,123 shares of New Common Stock for issuance to Gulfport's employees and non-employee directors pursuant to equity incentive awards to be granted under the Incentive Plan.

Additionally, pursuant to the Plan confirmed by the Bankruptcy Court, the Company's post-emergence Board of Directors is comprised of five directors, including the Company's Chief Executive Officer, Timothy Cutt, and four non-employee directors, David Wolf, Guillermo Martinez, Jason Martinez and David Reganato.

Executory Contracts

Subject to certain exceptions, under the Bankruptcy Code the Debtors were entitled to assume, assign or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and fulfillment of certain other conditions. Generally, the rejection of an executory contract was treated as a pre-petition breach of such contract and, subject to certain exceptions, relieved the Debtors from performing future obligations under such contract but entitled the counterparty to a pre-petition general unsecured claim for damages caused by such deemed breach. Alternatively, the assumption of an executory contract or unexpired lease required the Debtors to cure existing monetary defaults under such executory contract or unexpired lease, if any, and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this document, including where applicable quantification of the Company’s obligations under such executory or unexpired lease of the Debtors, is qualified by any overriding rejection rights the Company has under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights thereto. Refer to Note 19 for more information on potential future rejection damages related to general unsecured claims.

3. FRESH START ACCOUNTING

In connection with the Company's emergence from bankruptcy and in accordance with ASC 852, the Company qualified for and applied fresh start accounting on the Emergence Date. The Company qualified for fresh start accounting because (1) the holders of existing voting shares of the Company prior to the Emergence Date received less than 50% of the voting shares of the Successor's equity following its emergence from bankruptcy and (2) the reorganization value of the Company's assets immediately prior to confirmation of the Plan of approximately $2.3 billion was less than the post-petition liabilities and allowed claims of $3.1 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 May 17, 2021 are not comparable with the consolidated financial statements as of or prior to that date. The Emergence 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 $1.3 billion and $1.9 billion. With the assistance of third-party valuation advisors, the Company 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. Deferred income taxes were determined in accordance with FASB ASC Topic 740 - *Income Taxes.* 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 $1.6 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 May 17, 2021. As 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, the resolution of contingencies is 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 Emergence Date (in thousands):

Enterprise Value	$	1,600,000
Plus: Cash and cash equivalents[1]		1,526
Less: Fair value of debt		(852,751)
Successor equity value[2]	$	748,775

(1) Restricted cash is not included in the above table.
(2) Inclusive of $55 million of mezzanine equity.

The following table reconciles the enterprise value to the reorganization value as of the Emergence Date (in thousands):

Enterprise Value	$	1,600,000
Plus: Cash and cash equivalents[1]		1,526
Plus: Current and other liabilities		686,489
Plus: Asset retirement obligations		19,084
Less: Common stock reserved for settlement of claims post Emergence Date		(54,109)
Reorganization value of Successor assets	$	2,252,990

(1) Restricted cash is not included in the above table.

The fair values of our oil and natural gas properties, other property and equipment, derivative instruments, equity investments and asset retirement obligations were estimated as of the Emergence Date.

Oil and natural gas properties. The Company's principal assets are its oil and natural gas properties, which are accounted for under the full cost method of accounting. The Company determined the fair value of its oil and natural gas properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area were prepared using the estimated future revenues and operating costs for all developed wells 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 seven 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 land, buildings, vehicles, computer equipment and other equipment, was maintained at net book value as the carrying value reasonably approximated the fair value of the assets.

Asset retirement obligations. In accordance with FASB ASC Topic 410 -*Asset Retirement and Environmental Obligations* ("ASC 410"), the asset retirement obligations associated with the Company's oil and gas assets was valued using the income approach. The fair value of the Company’s asset retirement obligations was revalued based upon estimated current reclamation costs for our assets with reclamation obligations, updated estimates of timing of reclamation obligations, an appropriate long-term inflation adjustment, and the Company's 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 the Company's credit standing.

Derivative Instruments. The fair value of derivative instruments was adjusted based on the change in the Company’s credit rating reflecting the Company’s credit standing at the Emergence Date.

Equity Investments. The fair value of the Company's investment in Grizzly was reduced by $27 million. The reduction in valuation was based upon the assessment of the investment by the Company's new management and its priority for future funding in its portfolio. In particular, Grizzly’s operations remained suspended, even with improvements in the pricing environment since its initial suspension in 2015. Additionally, the Company does not anticipate funding future capital calls which will lead to further dilution of its equity ownership interest.

Consolidated Balance Sheet

The following consolidated balance sheet is as of May 17, 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 Emergence 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 and liabilities.

	As of May 17, 2021					
	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
	(In thousands)					
Assets						
Current assets:						
Cash and cash equivalents	$ 146,545	$ (145,019)	(a)	$ —		$ 1,526
Restricted cash	—	57,891	(b)	—		57,891
Accounts receivable—oil and natural gas sales	180,711	—		—		180,711
Accounts receivable—joint interest and other	15,431	—		—		15,431
Prepaid expenses and other current assets	86,189	(60,894)	(c)	—		25,295
Short-term derivative instruments	3,324	—		141	(r)	3,465
Total current assets	432,200	(148,022)		141		284,319
Property and equipment:						
Oil and natural gas properties, full-cost method						
Proved oil and natural gas properties	9,558,121	—		(7,860,713)	(s)	1,697,408
Unproved properties	1,375,681	—		(1,145,507)	(s)	230,174
Other property and equipment	38,026	—		(31,133)	(t)	6,893
Total property and equipment	10,971,828	—		(9,037,353)		1,934,475
Accumulated depletion, depreciation and amortization	(8,870,723)	—		8,870,723	(u)	—
Total property and equipment, net	2,101,105	—		(166,630)		1,934,475
Other assets:						
Equity investments	27,044	—		(27,044)	(v)	—
Long-term derivative instruments	7,468	—		715	(w)	8,183
Operating lease assets	47	—		—		47
Other assets	18,866	7,100	(d)	—		25,966
Total other assets	53,425	7,100		(26,329)		34,196
Total assets	$ 2,586,730	$ (140,922)		$ (192,818)		$ 2,252,990

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
	(In thousands)					
Liabilities and Stockholders' Equity (Deficit)						
Current liabilities:						
Accounts payable and accrued liabilities	$ 384,200	$ 122,599	(e)	$ —		$ 506,799
Short-term derivative instruments	96,116	—		2,784	(x)	98,900
Current portion of operating lease liabilities	—	38	(f)	—		38
Current maturities of long-term debt	280,251	(220,251)	(g)	—		60,000
Total current liabilities	760,567	(97,614)		2,784		665,737
Non-current liabilities:						
Long-term derivative instruments	69,331	—		11,411	(y)	80,742
Asset retirement obligation	—	65,341	(h)	(46,257)	(z)	19,084
Non-current operating lease liabilities	—	9	(i)	—		9
Long-term debt, net of current maturities	—	792,751	(j)	—		792,751
Total non-current liabilities	69,331	858,101		(34,846)		892,586
Liabilities subject to compromise	2,224,449	(2,224,449)	(k)	—		—
Total liabilities	$ 3,054,347	$ (1,463,962)		$ (32,062)		$ 1,558,323
Commitments and contingencies						
Mezzanine Equity:						
New Preferred Stock	$ —	$ 55,000	(l)	$ —		$ 55,000
Stockholders' equity (deficit):						
Predecessor common stock	1,609	(1,609)	(m)	—		—
New Common Stock	—	2	(n)	—		2
Additional paid-in capital	4,215,838	(3,522,064)	(o)	—		693,774
New Common Stock held in reserve	—	(54,109)	(p)	—		(54,109)
Accumulated other comprehensive loss	(40,430)	40,430	(q)	—		—
Retained earnings (accumulated deficit)	(4,644,634)	4,805,390	(q)	(160,756)	(aa)	—
Total stockholders' equity (deficit)	$ (467,617)	$ 1,268,040		$ (160,756)		$ 639,667
Total liabilities, mezzanine equity and stockholders' equity (deficit)	$ 2,586,730	$ (140,922)		$ (192,818)		$ 2,252,990

Reorganization Adjustments (in thousands)

(a) The table below reflects changes in cash and cash equivalents on the Emergence Date from implementation of the Plan:

Release of escrow funds by counterparties as a result of the Plan	$	63,068
New Preferred Stock rights offering proceeds		50,000
Funds required to rollover the DIP Credit Facility and Pre-Petition Revolving Credit Facility into the Exit Facility		(175,000)
Payment of accrued Pre-Petition Revolving Credit Facility and DIP Credit Facility interest		(1,022)
Payment of issuance costs related to the Exit Credit Facility		(10,250)
Funding of the Professional Fee Escrow		(43,891)
Payment of professional fees at Emergence Date		(7,964)
Transfer to restricted cash for the Unsecured Claims Distribution Trust		(1,000)
Transfer to restricted cash for the Convenience Claims Cash Pool		(3,000)
Transfer to restricted cash for the Parent Cash Pool		(10,000)
Payment of severance costs at Emergence Date		(5,960)
Net change in cash and cash equivalents	$	(145,019)

(b) Changes in restricted cash reflect the net effect of transfers from cash and cash equivalents for the Professional Fee Escrow and various claims class cash pools.

(c) Changes in prepaid expenses and other current assets include the following:

Release of escrow funds as a result of the Plan	$	(63,068)
Recognition of counterparty credits due to settlements effectuated at Emergence		4,247
Prepaid compensation earned at Emergence		(2,073)
Net change in prepaid expenses and other current assets	$	(60,894)

(d) Changes in other assets were due to capitalization of debt issuance costs related to the Exit Credit Facility.

(e) Changes in accounts payable and accrued liabilities included the following:

Payment of accrued Pre-Petition Revolving Credit Facility and DIP Credit Facility interest	$	(1,022)
Payment of professional fees at emergence		(7,964)
Accrued payable for claims to be settled via Unsecured Claims Distribution Trust		1,000
Accrued payable for claims to be settled via Convenience Claims Cash Pool		3,000
Accrued payable for claims to be settled via Parent Cash Pool		10,000
Professional fees payable at Emergence		18,047
Accrued payable for General Unsecured Claims against Gulfport Parent to be settled via 4A Claims distribution from common shares held in reserve		23,894
Accrued payable for General Unsecured Claims against Gulfport Subsidiary to be settled via 4B Claims distribution from common shares held in reserve		30,216
Reinstatement of payables due to Plan effects		45,428
Net change in accounts payable and accrued liabilities	$	122,599

(f) Changes to current operating lease liabilities reflect the reinstatement of lease liabilities due to contract assumptions.

(g) Changes in the current maturities of long-term debt include the following:

Current portion of Term Notes issued under the Exit Facility	$	60,000
Payment of DIP Facility to effectuate Exit Facility		(157,500)
Transfer of post-petition RBL borrowings to Exit Facility		(122,751)
Net changes to current maturities of long-term debt	$	(220,251)

(h) Reflects the reclassification of asset retirement obligations from liabilities subject to compromise.

(i) Changes to non-current operating lease liabilities reflect the reinstatement of lease liabilities due to contract assumptions.

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

Emergence Date draw on Exit Facility	$	122,751
Noncurrent portion of First-Out Term Loan issued under the Exit Credit Facility		120,000
Issuance of Successor Senior Notes		550,000
Net impact to long-term debt, net of current maturities	$	792,751

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

General Unsecured Claims settled via Class 4A, 4B, and 5B distributions	$	74,098
Predecessor Senior Notes and associated interest		1,842,035
Pre-Petition Revolving Credit Facility		197,500
Reinstatement of Predecessor Claims as Successor liabilities		45,475
Reinstatement of Predecessor asset retirement obligations		65,341
Total liabilities subject to compromise settled in accordance with the Plan	$	2,224,449

The resulting gain on liabilities subject to compromise was determined as follows:

Pre-petition General Unsecured Claims Settled at Emergence	$	74,098
Predecessor Senior Notes Claims settled at Emergence		1,842,035
Pre-Petition Revolving Credit Facility		197,500
Rollover of Pre-Petition Revolving Credit Facility into Exit RBL Facility		(197,500)
Accrued payable for claims to be settled via Unsecured Claims Distribution Trust		(1,000)
Accrued payable for claims to be settled via Convenience Claims Cash Pool		(3,000)
Accrued payable for claims to be settled via Parent Cash Pool		(10,000)
Accrued payable for shares to be transferred to trust		(54,109)
Issuance of New Common Stock to settle Predecessor liabilities		(639,666)
Issuance of Successor Senior Notes in settlement of Class 4B and 5B claims		(550,000)
Gain on settlement of liabilities subject to compromise	$	658,358

(l) Changes to New Preferred Stock reflect the fair value of preferred shares issued in the Rights Offering.

(m) Changes in Predecessor common stock reflect the extinguishment of Predecessor equity as per the Plan.

(n) Changes in New Common Stock included the following:

Issuance of common stock to settle General Unsecured Claims against Gulfport Parent (par value)	$	—
Issuance of common stock to settle General Unsecured Claims against Gulfport Subsidiaries (par value)		2
Common stock reserved for settlement of claims post Emergence Date (par value)		—
Net change to New Common Stock	$	2

(o) Changes to paid in capital included the following:

Issuance of common stock to settle General Unsecured Claims against Gulfport Parent	$	27,751
Issuance of common stock to settle General Unsecured Claims against Gulfport Subsidiaries		666,022
Extinguishment of Predecessor stock-based compensation		4,419
Extinguishment of Predecessor paid in capital		(4,220,256)
Net change to paid in capital	$	(3,522,064)

(p) New Common Stock held in reserve to settle Allowed General Unsecured Claims include:

Shares held in reserve to settle Allowed Claims against Gulfport Parent		(23,894)
Shares held in reserve to settle Allowed Claims against Gulfport Subsidiary		(30,215)
Total New Common Stock held in reserve	$	(54,109)

(q) Change to retained earnings (accumulated deficit) included the following:

Gain on settlement of liabilities subject to compromise	$	658,358
Extinguishment of Predecessor common stock and paid in capital		4,221,864
Recognition of counterparty credits due to settlements effectuated at Emergence		4,247
Deferred compensation earned at Emergence		(2,073)
Extinguishment of Predecessor accumulated other comprehensive income		(40,430)
Write-off of debt issuance costs related to First-Out Term Loan		(3,150)
Severance costs incurred as a result of the Plan		(5,961)
Professional fees earned at Emergence		(18,047)
Rights offering backstop commitment fee		(5,000)
Extinguishment of Predecessor stock-based compensation		(4,418)
Net change to retained earnings (accumulated deficit)	$	4,805,390

Fresh Start Adjustments

(r) The change in fair value of short-term derivative instruments is due to the change in the Company's post-emergence credit rating.

(s) The change in oil and natural gas properties represents the fair value adjustment to the Company's properties due to the adoption of fresh start accounting.

(t) Predecessor accumulated depreciation and amortization for other property and equipment was net against the gross value of the assets with the adoption of fresh start accounting.

(u) Predecessor accumulated depreciation and amortization was eliminated with the adoption of fresh start accounting.

(v) The change in equity investments is due to the fair value adjustment to the Company's Grizzly investment.

(w) The change in fair value of long-term derivative instruments is due to the change in the Company's post-emergence credit rating.

(x) The change in fair value of liabilities related to short-term derivative instruments is due to the change in the Company's post-emergence credit rating.

(y) The change in fair value of liabilities related to long-term derivative instruments is due to the change in the Company's post-emergence credit rating.

(z) The fair value of asset retirement obligations was reduced due to the change in the Company's credit adjusted risk-free rate and expected economic life estimates.

(aa) Changes to retained earnings represent the total impact of fresh start adjustments to the post-reorganization balance sheet.

Reorganization Items, Net

The Company has incurred significant expenses, gains and losses associated with the reorganization, primarily the gain on settlement of liabilities subject to compromise, 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, the estimate of liabilities related to the rejection of certain midstream contracts reflects the best estimate of the most probable outcomes of ongoing litigation and settlement negotiations. The amount of these items, which were incurred in reorganization items, net within the accompanying unaudited condensed consolidated statements of operations, have significantly affected the Company's statements of operations.

The following table summarizes the components in reorganization items, net included in the Company's unaudited consolidated statements of operations (in thousands):

	Successor	Predecessor
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021
Legal and professional advisory fees	$ —	$ (81,565)
Net gain on liabilities subject to compromise	—	575,182
Fresh start adjustments, net	—	(160,756)
Elimination of predecessor accumulated other comprehensive income	—	(40,430)
Debt issuance costs	—	(3,150)
Other items, net	—	(22,383)
Total reorganization items, net	$ —	$ 266,898

4. DIVESTITURES

Sale of Water Infrastructure Assets

On January 2, 2020, the Company closed on the sale of its SCOOP water infrastructure assets to a third-party water service provider. The Company received $50.0 million in cash proceeds upon closing and has an opportunity to earn potential additional incentive payments over the next 14 years, subject to the Company's ability to meet certain thresholds which will be driven by, among other things, the Company's future development program and water production levels. The agreement contained no minimum volume commitments. The fair value of the contingent consideration as of the closing date was $23.1 million. See Note 16 for additional discussion of the fair value of the contingent consideration.

The divested assets were included in the amortization base of the full cost pool and no gain or loss was recognized in the accompanying consolidated statements of operations as a result of the sale.

5. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2021 and 2020 are as follows (in thousands):

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Proved oil and natural gas properties	$ 1,917,833	$ 9,359,866
Unproved properties	211,007	1,457,043
Other depreciable property and equipment	4,943	85,530
Land	386	3,008
Total property and equipment	2,134,169	10,905,447
Accumulated depletion, depreciation, amortization and impairment	(278,341)	(8,819,178)
Property and equipment, net	$ 1,855,828	$ 2,086,269

As discussed in Note 3. the Company recorded its property, plant and equipment at fair value as of the Emergence Date.

Oil and Natural Gas Properties

Under the full cost method of accounting, capitalized costs of oil and natural gas properties are subject to a quarterly full cost ceiling test, which is discussed in Note 1. During the Successor Period and the years ended December 31, 2020, and 2019, the Company incurred $117.8 million, $1.4 billion, and $2.0 billion of impairments, respectively, as a result of its oil and natural gas properties exceeding its calculated ceiling. The lower ceiling values resulted primarily from significant decreases in the 12-month average trailing prices for natural gas, oil and NGL, which significantly reduced proved reserves values and proved reserves. The Company did not record an impairment of its oil and natural gas properties during the 2021 Predecessor Period.

General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $8.0 million, $11.9 million, $25.0 million and $30.1 million for the Predecessor Period, the Successor Period, and the years ended December 31, 2020 and 2019, respectively. The average depletion rate per Mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $0.69, $0.45, $0.61 and $1.08 per Mcfe for the Successor Period, the Predecessor Period, and the years ended December 31, 2020 and 2019, respectively.

The following is a summary of Gulfport's oil and natural gas properties not subject to amortization as of December 31, 2021 (in thousands):

	Costs Incurred in		
	Period from May 18, 2021 through December 31, 2021	Fresh Start Adjustments (May 17, 2021)(1)	Total
Acquisition costs	$ 8,687	$ 202,296	$ 210,983
Exploration costs	—	—	—
Development costs	18	—	18
Capitalized interest	6	—	6
Total oil and natural gas properties not subject to amortization	$ 8,711	$ 202,296	$ 211,007

(1) Reflects carrying values of our unproved properties as a result of the application of fresh start accounting upon emergence from bankruptcy (see Note 3 for additional information) that remain in unproved properties as of December 31, 2021.

The following table summarizes the Company’s non-producing properties excluded from amortization by area as of December 31, 2021:

	Successor
	December 31, 2021
	(In thousands)
Utica	$ 175,028
SCOOP	35,975
Other	4
	$ 211,007

As of December 31, 2020, approximately $1.5 billion of non-producing property costs were subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company’s activities, the inclusion of most of the above referenced costs into the Company’s amortization calculation typically occurs within three to five years. However, the majority of the Company's non-producing leases in the Utica have five-year extension terms which could extend this time frame beyond five years.

Asset Retirement Obligation

A reconciliation of the Company's asset retirement obligation for the Predecessor Period, the Successor Period, and the year ended December 31, 2020 is as follows (in thousands):

Asset retirement obligation, January 1, 2020 (Predecessor)	$ 60,355
Liabilities incurred	2,358
Liabilities removed due to divestitures	(2,213)
Accretion expense	3,066
Total asset retirement obligation, December 31, 2020 (Predecessor)	63,566
Less: amounts reclassified to liabilities subject to compromise	(63,566)
Total asset retirement obligation reflected as non-current liabilities, December 31, 2020 (Predecessor)	$ —
Asset retirement obligation at January 1, 2021 (Predecessor)	$ 63,566
Liabilities incurred	546
Accretion expense	1,229
Ending balance as of May 17, 2021 (Predecessor)	$ 65,341
Fresh start adjustments[1]	(46,257)
Asset retirement obligation at May 18, 2021 (Successor)	$ 19,084
Liabilities incurred	204
Accretion expense	1,214
Revisions in estimated cash flows[2]	7,762
Asset retirement obligation at December 31, 2021 (Successor)	$ 28,264

(1) As discussed in Note 3, the Company recorded its asset retirement obligation at fair value as of the Emergence Date.
(2) Revisions represent changes in the present value of liabilities resulting from changes in estimated costs.

6. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31, 2021 and 2020 (in thousands):

	Successor	Predecessor
	December 31, 2021	December 31, 2020
New Credit Facility	$ 164,000	$ —
8.000% senior unsecured notes due 2026	550,000	—
DIP credit facility	—	157,500
Pre-petition revolving credit facility	—	292,910
6.625% senior unsecured notes due 2023	—	324,583
6.000% senior unsecured notes due 2024	—	579,568
6.375% senior unsecured notes due 2025	—	507,870
6.375% senior unsecured notes due 2026	—	374,617
Building loan	—	21,914
Net unamortized debt issuance costs	(1,054)	—
Total Debt, net	712,946	2,258,962
Less: current maturities of long term debt	—	(253,743)
Less: amounts reclassified to liabilities subject to compromise	—	(2,005,219)
Total Debt reflected as long term	$ 712,946	$ —

Of the total debt outstanding on December 31, 2021, the New Credit Facility, which matures October 14, 2025, and the 8.000% Senior Notes due May 17, 2026, will mature within the next five years.

Successor Debt

Our post-emergence debt consisted of the Successor Senior Notes and the Exit Credit Facility, which was amended and refinanced in October 2021 with the New Credit Facility.

New Credit Facility

On October 14, 2021, the Company entered into the Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and various lender parties ("New Credit Facility"). The New Credit Facility provides for an aggregate maximum principal amount of up to $1.5 billion, an initial borrowing base of $850.0 million and an initial aggregate elected commitment amount of $700.0 million. The credit agreement also provides for a $175.0 million sublimit of the aggregate commitments that is available for the issuance of letters of credit. The New Credit Facility amended and refinanced the Exit Credit Facility.

As of December 31, 2021, the Company had $164.0 million outstanding borrowings under the New Credit Facility and $122.1 million in letters of credit outstanding. As of December 31, 2021, the Company was in compliance with all covenants under the New Credit Facility.

The borrowing base will be redetermined semiannually on or around May 1 and November 1 of each year, with the first scheduled redetermination to be on or around May 1, 2022.

The New Credit Facility bears interest at a rate equal to, at the Company's election, either (a) LIBOR plus an applicable margin that varies from 2.75% to 3.75% per annum or (b) a base rate plus an applicable margin that varies from 1.75% to 2.75% per annum, based on borrowing base utilization. The New Credit Facility will mature on October 14, 2025. The Company is required to pay a commitment fee of 0.50% per annum on the average daily unused portion of the current aggregate commitments under the New Credit Facility. The Company is also required to pay customary letter of credit and fronting fees.

As of December 31, 2021, the New Credit Facility bore interest at a weighted average rate of 3.19%.

The credit agreement requires the Company to maintain as of the last day of each fiscal quarter (i) a net funded leverage ratio of less than or equal to 3.25 to 1.00, and (ii) a current ratio of greater than or equal to 1.00 to 1.00.

The obligations under the New Credit Facility, certain swap obligations and certain cash management obligations, are guaranteed by the Company and the wholly-owned domestic material subsidiaries of the Borrower (collectively, the "Guarantors" and, together with the Borrower, the "Loan Parties") and secured by substantially all of the Loan Parties' assets (subject to customary exceptions).

The credit agreement also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements and borrowing base certificates, conduct of business, maintenance of property, maintenance of insurance, entry into certain derivatives contracts, restrictions on the incurrence of liens, indebtedness, asset dispositions, restricted payments, and other customary covenants. These covenants are subject to a number of limitations and exceptions.

Successor Senior Notes

As discussed in Note 2, on the Emergence Date, pursuant to the terms of the Plan, the Company issued $550 million aggregate principal amount of its 8.000% senior notes due 2026.

The notes are guaranteed on a senior unsecured basis by each of the Company's subsidiaries that guarantee the New Credit Facility.

Interest on the Successor Senior Notes will be payable semi-annually, on June 1 and December 1 of each year.

The Successor Senior Notes were issued under the Indentures, dated as of May 17, 2021, by and among the Issuer, UMB Bank, National Association, as trustee, and the Guarantors.

The covenants of the 1145 Indenture (other than the payment covenant) require that the Company comply with the covenants of the 4(a)(2) Indenture, as amended. The 4(a)(2) Indenture contains covenants limiting the Issuer's and its restricted subsidiaries' ability to (i) incur additional debt, (ii) pay dividends or distributions in respect of certain equity interests or redeem, repurchase or retire certain equity interests or subordinated indebtedness, (iii) make certain investments, (iv) create restrictions on distributions from restricted subsidiaries, (v) engage in specified sales of assets, (vi) enter into certain transactions among affiliates, (vii) engage in certain lines of business, (viii) engage in consolidations, mergers and acquisitions, (ix) create unrestricted subsidiaries and (x) incur or create liens. These covenants contain important exceptions, limitations and qualifications. At any time that the Successor Senior Notes are rated investment grade, certain covenants will be terminated and cease to apply.

Exit Credit Facility

As discussed in Note 2, on the Emergence Date, pursuant to the terms of the Plan, the Company entered into the Exit Credit Agreement, which provided for (i) the Exit Facility in an aggregate principal amount of up to $1.5 billion and (ii) the First-Out Term Loan in an aggregate maximum amount of up to $180.0 million. The Exit Facility had an initial borrowing base and elected commitment amount of up to $580.0 million.

Loans drawn under the Exit Facility were not subject to amortization, while loans drawn under the First-Out Term Loan amortized with $15.0 million quarterly installments, commencing on the closing date and occurring every three months after the closing date. The Exit Credit Facility was scheduled to mature on May 17, 2024.

The Exit Facility provided for a $150.0 million sublimit of the aggregate commitments that is available for the issuance of letters of credit. The Exit Facility also included a $40 million availability blocker that was to remain in place until Successful Midstream Resolution (as defined in the Exit Credit Agreement). The New Credit Facility amended and refinanced the Exit Credit Facility.

Chapter 11 Proceedings - Predecessor Debt

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

The principal amounts from the Predecessor Senior Notes, Building Loan and Pre-Petition Revolving Credit Facility, other than letters of credit drawn on the Pre-Petition Revolving Credit Facility after the Petition Date, were classified as liabilities subject to compromise on the accompanying consolidated balance sheet as of December 31, 2020.

Debtor-in-Possession Credit Agreement

Pursuant to the RSA, the Consenting RBL Lenders agreed to provide the Company with a senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million consisting of (a) $105 million of new money and (b) $157.5 million to roll up a portion of the existing outstanding obligations under the Pre-Petition Revolving Credit Facility. The terms and conditions of the DIP Credit Facility are set forth in that certain form of credit agreement governing the DIP Credit Facility. The proceeds of the DIP Credit Facility were used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases and payment of court approved adequate protection obligations. On the Emergence Date, the DIP Facility was terminated and the lenders indefeasibly converted into the Exit Facility. Each holder of an allowed DIP Claim received, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Allowed DIP Claim its Pro Rata share of participation in the Exit Credit Facility.

Pre-Petition Revolving Credit Facility

Prior to the Emergence Date, the Company had entered into a senior secured revolving credit facility agreement, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The Pre-Petition Revolving Credit Facility had a borrowing base of $580 million. On the Emergence Date, the Pre-Petition Revolving Credit Facility was terminated and the lenders indefeasibly converted into the Exit Credit Facility. Each holder of an allowed claim under the Pre-Petition Revolving Credit Facility received, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Allowed DIP Claim its Pro Rata share of participation in the Exit Credit Facility.

Predecessor Senior Notes

On the Emergence Date, all outstanding obligations under the Predecessor Senior Notes were cancelled in accordance with the Plan and each holder of an allowed unsecured notes claim received their pro-rata share of 19.7 million shares of New Common Stock and $550 million of the Successor Senior Notes.

Predecessor Building Loan

In June 2015, the Company entered into a loan for the construction of the Company's corporate headquarters in Oklahoma City, which was substantially completed in December 2016. On the Emergence Date, ownership of the Company's corporate headquarters reverted to the Building Loan lender and the Company entered into a short-term lease agreement for the headquarters with the lender. As a result, the building loan liability was discharged as of the Emergence Date.

Predecessor Debt Repurchases

In July of 2019, the Company's Board of Directors authorized $100 million of cash to be used to repurchase its Senior Notes in the open market at discounted values to par. In December 2019, the Company's Board of Directors increased the authorized size of its senior note repurchase program to $200 million in total. During the year ended December 31, 2020, the Company used borrowings under its revolving credit facility to repurchase in the open market approximately $73.3 million aggregate principal amount of its outstanding Predecessor Senior Notes for $22.8 million in cash and recognized a $49.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt. This gain is included in gain on debt extinguishment in the accompanying consolidated statements of operations.

Interest Expense

The following schedule shows the components of interest expense for the Successor Period, Predecessor Period, and the years ended December 31, 2020, and 2019 (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash paid for interest	$ 33,295	$ 7,272	$ 84,823	$ 142,664
Change in accrued interest	6,061	(1,503)	30,600	(3,834)
Capitalized interest	(198)	—	(907)	(3,372)
Amortization of loan costs	1,663	—	5,563	6,328
Other	32	(1,610)	—	—
Total interest expense	$ 40,853	$ 4,159	$ 120,079	$ 141,786

The Company capitalized approximately $0.2 million and $0.9 million in interest expense to undeveloped oil and natural gas properties during the Successor Period and the year ended December 31, 2020, respectively. The Company did not capitalize interest expense for the Predecessor Period.

Fair Value of Debt

At December 31, 2021, the carrying value of the outstanding debt represented by the Successor Senior Notes was approximately $548.9 million. Based on the quoted market prices (Level 1), the fair value of the Successor Senior Notes was determined to be approximately $603.8 million at December 31, 2021.

7. EQUITY

As discussed in Note 2, the Company filed an amended and restated certificate of incorporation with the Delaware Secretary of State on the Emergence Date to provide for, among other things, (i) the authority to issue 42 million shares of New Common Stock with a par value of $0.0001 per share and (ii) the designation of 110,000 shares of New Preferred Stock, with a par value of $0.0001 per share and a liquidation preference of $1,000 per share.

New Common Stock

On the Emergence Date, all existing shares of the Predecessor's common stock were cancelled. The Successor issued approximately 19.8 million shares of New Common Stock and 1.7 million shares of New Common Stock were issued to the Disputed Claims reserve.

New Preferred Stock

On the Emergence Date, the Successor issued 55,000 shares of New Preferred Stock.

Holders of New Preferred Stock are entitled to receive cumulative quarterly dividends at a rate of 10% per annum of the Liquidation Preference (as defined below) with respect to cash dividends and 15% per annum of the Liquidation Preference with respect to dividends paid in kind as additional shares of New Preferred Stock (“PIK Dividends”). Gulfport was required to pay PIK Dividends for so long as the quotient obtained by dividing (i) Total Net Funded Debt (as defined in the Exit Credit Facility) by (ii) the last twelve months of EBITDAX (as defined in the Exit Credit Facility) calculated as at the applicable record date is equal to or greater than 1.50. If such ratio is less than 1.50 such dividend may be paid in either cash or as PIK Dividends, subject to certain conditions under the Company's credit agreement. This requirement with respect to PIK Dividends is no longer applicable upon the effective date of the New Credit Facility.

Each holder of shares of New Preferred Stock has the right (the "Conversion Right"), at its option and at any time, to convert all or a portion of the shares of New Preferred Stock that it holds into a number of shares of Common Stock equal to the quotient obtained by dividing (x) the product obtained by multiplying (i) the Liquidation Preference times (ii) an amount equal to one (1) plus the Per Share Makewhole Amount (as defined in the Preferred Terms) on the date of conversion, by (y) $14.00 per share (as may be adjusted under the Preferred Terms) (the "Conversion Price"). The shares of New Preferred Stock outstanding at December 31, 2021 would convert to 4.1 million shares of New Common Stock if all holders of New Preferred Stock exercised their Conversion Right.

Gulfport shall have the right, but not the obligation, to redeem all, but not less than all, of the outstanding shares of New Preferred Stock by notice to the holders of New Preferred Stock, at the greater of (i) the aggregate value of the New Preferred Stock, calculated by the Current Market Price (as defined in the Preferred Terms) of the number of shares of Common Stock into which, subject to redemption, such New Preferred Stock would have been converted if such shares were converted pursuant to the Conversion Right at the time of such redemption and (ii) (y) if the date of such redemption is on or prior to the three year anniversary of the Emergence Date, the sum of the Liquidation Preference plus the sum of all unpaid PIK Dividends through the three year anniversary of the Emergence Date, or (x) if the date of such redemption is after the three year anniversary of the Emergence Date, the Liquidation Preference (the "Redemption Price").

Following the Emergence Date, if there is a Fundamental Change (as defined in the Preferred Terms), Gulfport is required to redeem all, but not less than all, of the outstanding shares of New Preferred Stock by cash payment of the Redemption Price per share of New Preferred Stock within three (3) business days of the occurrence of such Fundamental Change. Notwithstanding the foregoing, in the event of a redemption pursuant to the preceding sentence, if Gulfport lacks sufficient cash to redeem all outstanding shares of New Preferred Stock, the Company is required to redeem a pro rata portion of each holder's shares of New Preferred Stock.

The New Preferred Stock has no stated maturity and will remain outstanding indefinitely unless repurchased or redeemed by Gulfport or converted into Common Stock.

The New Preferred Stock has been classified as mezzanine equity in the accompanying consolidated balance sheets due to the redemption features noted above.

Dividends

During the Successor Period, the company paid dividends on its New Preferred Stock, which included3,071 shares of New Preferred Stock paid in kind, approximately $55 thousand of cash-in-lieu of fractional shares, and $1.5 million of cash dividends to holders of our New Preferred Stock. The following table summarizes PIK dividends and conversions of the Company's New Preferred Stock subsequent to the Emergence Date:

New Preferred Stock at May 18, 2021 (Successor)	55,000
Issuance of New Preferred Stock	3,071
Conversion of New Preferred Stock	(175)
New Preferred Stock at December 31, 2021	57,896

Share Repurchase Program

On November 1, 2021, the Company's Board of Directors approved a stock repurchase program to acquire up to $100.0 million of its New Common Stock. Purchases under the Repurchase Program may be made from time to time in open market or privately negotiated transactions, and will be subject to available liquidity, market conditions, credit agreement restrictions, applicable legal requirements, contractual obligations and other factors. The Repurchase Program does not require the Company to acquire any specific number of shares of New Common Stock. The Company intends to purchase shares under the Repurchase Program opportunistically with available funds while maintaining sufficient liquidity to fund its capital development program. The Repurchase Program is authorized to extend through December 31, 2022 and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. Any shares of New Common Stock repurchased are expected to be cancelled. No shares have been repurchased under the Repurchase Program as of December 31, 2021.

8. STOCK-BASED COMPENSATION

As discussed in Note 2, on the Emergence Date, the Company's Predecessor common stock was cancelled and New Common Stock was issued. Accordingly, the Company's then existing stock-based compensation awards were also cancelled, which resulted in the recognition of previously unamortized expense of $4.4 million related to the cancelled awards on the date of cancellation, which was included in reorganization items, net on the accompanying consolidated statements of operations. Stock-based compensation for the Predecessor and Successor periods are not comparable.

Successor Stock-Based Compensation

As of the Emergence Date, the board of directors adopted the Incentive Plan with a share reserve equal to 2,828,123 shares of New Common Stock. The Incentive Plan provides for the grant of incentive stock options, nonstatutory stock options, restricted stock, restricted stock units, stock appreciation rights, dividend equivalents and performance awards or any combination of the foregoing. The Company has granted both restricted stock units and performance vesting restricted stock units to employees and directors pursuant to the Incentive Plan, as discussed below. During the Successor Period, the Company's stock-based compensation expense was $3.1 million, of which the Company capitalized $1.1 million relating to its exploration and development efforts. Stock compensation expense, net of the amounts capitalized, is included in general and administrative expenses in the accompanying consolidated statements of operations. As of December 31, 2021, the Company has awarded an aggregate of 198 thousand restricted stock units and 153 thousand performance vesting restricted stock units under the Incentive Plan.

The following table summarizes restricted stock unit and performance vesting restricted stock unit activity for the Successor Period:

	Number of Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value	Number of Unvested Performance Vesting Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested shares as of May 18, 2021	—	$ —	—	$ —
Granted	200,484	66.05	153,138	48.54
Vested	—	—	—	—
Forfeited/cancelled	(2,071)	66.89	—	—
Unvested shares as of December 31, 2021	198,413	$ 66.04	153,138	$ 48.54

Successor Restricted Stock Units

Restricted stock units awarded under the Incentive Plan generally vest over a period of 1 to 4 years in the case of employees and 4 years in the case of directors upon the recipient meeting applicable service requirements. Stock-based compensation expense is recorded ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of the grant. Unrecognized compensation expense as of December 31, 2021, was $11.1 million. The expense is expected to be recognized over a weighted average period of 2.8 years.

Successor Performance Vesting Restricted Stock Units

The Company has awarded performance vesting restricted stock units to certain of its executive officers under the Incentive Plan. The number of shares of common stock issued pursuant to the award will be based on a combination of (i) the Company's total shareholder return ("TSR") and (ii) the Company's relative total shareholder return ("RTSR") for the performance period. Participants will earn from 0% to 200% of the target award based on the Company's TSR and RTSR ranking compared to the TSR of the companies in the Company's designated peer group at the end of the performance period. Awards will be earned and vested over a performance period from May 17, 2021 to May 17, 2024, subject to earlier termination of the performance period in the event of a change in control. The grant date fair values were determined using the Monte Carlo simulation method and are being recorded ratably over the performance period. Expected volatilities utilized in the Monte Carlo models were estimated using a historical period consistent with the remaining performance period of approximately 3 years. The risk-free interest rates were based on the U.S. Treasury rate for a term commensurate with the expected life of the grant. The Company assumed a range of risk-free interest rates between 0.35% and 0.67% and a range of expected volatilities between 87.0% and 87.1% to estimate the fair value. Unrecognized compensation expense as of December 31, 2021, related to performance vesting restricted shares was $6.3 million. The expense is expected to be recognized over a weighted average period of 2.4 years.

Predecessor Stock-Based Compensation

The Predecessor granted restricted stock units to employees and directors pursuant to the 2019 Plan. During the Predecessor Period, the Company's stock-based compensation cost was $4.4 million, of which the Company capitalized $0.9 million, relating to its exploration and development efforts. During the years ended December 31, 2020 and December 31, 2019, the Company's stock-based compensation cost was $16.3 million and $10.7 million, respectively, of which the Company capitalized $2.9 million and $5.8 million, respectively, relating to its exploration and development efforts. Stock compensation costs, net of the amounts capitalized, are included in general and administrative expenses in the accompanying consolidated statements of operations.

The following table summarizes restricted stock unit activity for the Predecessor Period and the Predecessor years ended December 31, 2020 and 2019:

	Number of Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value	Number of Unvested Performance Vesting Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2018	1,535,811	$ 11.57	—	$ —
Granted	4,011,073	$ 3.74	2,009,144	2.85
Vested	(676,108)	12.89	—	—
Forfeited	(772,458)	6.05	(225,484)	1.98
Unvested shares as of December 31, 2019	4,098,318	$ 4.73	1,783,660	$ 2.96
Granted	3,069,521	0.85	—	—
Vested	(1,294,285)	5.73	—	—
Forfeited	(4,171,041)	1.68	(943,065)	1.98
Unvested shares as of December 31, 2020	1,702,513	$ 4.74	840,595	$ 4.07
Granted	—	—	—	—
Vested	(227,132)	8.45	—	—
Forfeited/canceled	(1,475,381)	4.16	(840,595)	4.07
Unvested shares as of May 17, 2021	—	$ —	—	$ —

Predecessor Restricted Stock Units

Restricted stock units awarded under the 2019 Plan generally vested over a period ofone year in the case of directors andthree years in the case of employees and vesting was dependent upon the recipient meeting applicable service requirements. Stock-based compensation costs are recorded ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of grant. All unrecognized compensation expense was recognized as of the Emergence Date.

Predecessor Performance Vesting Restricted Stock Units

The Company previously awarded performance vesting restricted stock units to certain of its executive officers under the 2019 Plan. The number of shares of common stock issued pursuant to the award was based on RTSR. RTSR is an incentive measure whereby participants will earn from 0% to 200% of the target award based on the Company's TSR ranking compared to the TSR of the companies in the Company's designated peer group at the end of the performance period. Awards were to be earned and vested over a performance period measured from January 1, 2019 to December 31, 2021, subject to earlier termination of the performance period in the event of a change in control. All unrecognized compensation expense was recognized as of the Emergence Date.

9. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

The Company’s revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at the time control of the product is transferred to the customer. Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature generally through evergreen contracts with contract terms of one year or less. These contracts typically automatically renew under the same provisions. For those contracts, the Company has utilized the practical expedient allowed in the new revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, the Company's product sales that have a contractual term greater than one year have no long-term fixed consideration.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $232.9 million and $119.9 million as of December 31, 2021 and December 31, 2020, respectively, and are reported in accounts receivable - oil and natural gas sales in the accompanying consolidated balance sheets. The Company currently has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain sales may be received 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. For the year ended December 31, 2021, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

10. LEASES

Nature of Leases

The Company has operating leases on certain equipment with remaining lease durations in excess of one year. The Company recognizes right-of-use asset and current and non-current lease liabilities on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

The Company has entered into contracts for drilling rigs with varying terms with third parties to ensure operational continuity, cost control and rig availability in its operations. The Company has concluded its drilling rig contracts are operating leases as the assets are identifiable and the Company has the right to control the identified assets. The Company's drilling rig commitments are typically structured with an initial term of less than one to two years, although at December 31, 2021, the

Company did not have any active long-term drilling rig contracts in place. These agreements typically include renewal options at the end of the initial term. Due to the nature of the Company's drilling schedules and potential volatility in commodity prices, the Company is unable to determine at contract commencement with reasonable certainty if the renewal options will be exercised; therefore, renewal options are not considered in the lease term for drilling contracts. The operating lease liabilities associated with these rig commitments, when applicable, are based on the minimum contractual obligations, primarily standby rates, and do not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of drilling costs are borne by other interest owners in our wells.

The Company rents office space for its corporate headquarters, field locations and certain other equipment from third parties, which expire at various dates through 2023. These agreements are typically structured with non-cancelable terms of one to five years. The Company has determined these agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. The Company has included any renewal options that it has determined are reasonably certain of exercise in the determination of the lease terms. The lease for the Company's corporate headquarters has a primary term of one year and is classified as a short-term operating lease.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Future amounts due under operating lease liabilities as of December 31, 2021 were as follows:

	(In thousands)
2022	$ 187
2023	142
Total lease payments	329
Less: Imputed interest	(7)
Total lease liabilities	$ 322

Lease costs incurred for the Successor Period, Predecessor Period, and the year ended December 31, 2020 consisted of the following (in thousands):

	Successor	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020
Operating lease cost	$ 48	$ 41	$ 9,658
Variable lease cost	3	—	586
Short-term lease cost	11,507	4,496	9,361
Total lease cost[(1)]	$ 11,558	$ 4,537	$ 19,605

(1) The majority of the Company's total lease cost was capitalized to the full cost pool, and the remainder was included in either lease operating expenses or general and administrative expenses in the accompanying consolidated statements of operations.

Supplemental cash flow information for the Successor Period, Predecessor Period, and the year ended December 31, 2020 related to leases was as follows (in thousands):

	Successor	Predecessor	
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 78	$ 48	$ 140
Investing cash flow from operating leases	—	—	10,272
Investing cash flow from operating leases - related party	—	—	6,800

The weighted-average remaining lease term as of December 31, 2021 was 1.78 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2021 was 2.42%.

11. INCOME TAXES

Details of income tax provisions and deferred income taxes from continuing operations are provided in the following tables.

The components of income tax benefits and expense were as follows (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Current:				
State	$ (39)	$ (7,968)	$ —	$ —
Federal	—	—	(273)	(7)
Deferred:				
State	—	—	7,563	(7,556)
Federal	—	—	—	—
Total income tax (benefit) expense provision	$ (39)	$ (7,968)	$ 7,290	$ (7,563)

A reconciliation of the statutory federal income tax amount to the recorded expense follows (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
(Loss) income before federal income taxes	$ (112,868)	$ 243,026	$ (1,617,843)	$ (2,009,921)
Expected income tax at statutory rate	(23,702)	51,036	(339,747)	(422,083)
State income taxes	(3,177)	(12,484)	(14,696)	(28,316)
Bankruptcy adjustments	44,748	(111,285)		
Remeasurement of state deferred tax asset	(7,966)	—		
Other differences	2,841	445	10,800	3,372
Change in valuation allowance due to current year activity	(12,783)	64,320	350,933	439,464
Income tax (benefit) expense recorded	$ (39)	$ (7,968)	$ 7,290	$ (7,563)

For the Predecessor period ending May 17, 2021, the Company has an effective tax rate of (3.3)% and an income tax benefit of $8.0 million. The tax benefit is entirely attributable to an Oklahoma refund claim associated with an examination relating to historical tax returns. The effective tax rate differs from the statutory tax rate due to the Company's valuation allowance position and the permanent adjustments relating to the Chapter 11 Emergence. For the Successor Period, the Company has an effective tax rate of 0.03% and tax expense of $39 thousand. The tax expense is entirely attributable to the Oklahoma refund claim that was filed during the third quarter, resulting in an adjustment to the benefit recorded during the Predecessor Period. We did not record any additional income tax expense for the Successor Period as a result of maintaining a full valuation allowance against our net deferred tax asset.

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2021, and 2020 are estimated as follows (in thousands):

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Deferred tax assets:		
Net operating loss carryforward and tax credits	$ 298,127	$ 415,719
Oil and gas property basis difference	432,959	463,705
Investment in pass through entities	58,751	61,078
Change in fair value of derivative instruments	86,296	7,656
Other	31,298	41,292
Total deferred tax assets	907,431	989,450
Valuation allowance for deferred tax assets	(907,358)	(985,528)
Deferred tax assets, net of valuation allowance	73	3,922
Deferred tax liabilities:		
Other	73	3,922
Total deferred tax liabilities	73	3,922
Net deferred tax asset	$ —	$ —

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of the existing deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred over the three-year period ended December 31, 2021. Such objective evidence limits the ability to consider other subjective evidence, such as our projections for future growth. On the basis of this evaluation, as of December 31, 2021, a valuation allowance of $907.4 million has been recorded. The amount of the DTA considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as our projections for growth.

As discussed in Note 2, elements of the Plan provided that the Company's indebtedness related to Predecessor Senior Notes and certain general unsecured claims were exchanged for New Common Stock in settlement of those claims. Absent an exception, a debtor recognizes CODI upon discharge of its outstanding indebtedness for an amount of consideration that is less than its adjusted issue price. The IRC provides that a debtor in a Chapter 11 bankruptcy case may exclude CODI from taxable income, but must reduce certain of its tax attributes by the amount of any CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is determined based on the fair market value of the consideration received by the creditors in settlement of outstanding indebtedness. As a result of the market value of equity upon emergence from Chapter 11 bankruptcy proceedings, the estimated amount of CODI and historical interest expense haircut is approximately $661 million, which will reduce the value of the Company's net operating losses. The actual reduction in tax attributes does not occur until the first day of the Company's tax year subsequent to the date of emergence, or January 1, 2022. The reduction of net operating losses is expected to be fully offset by a corresponding decrease in valuation allowance. As of December 31, 2021, the Company had an estimated federal net operating loss carryforward of approximately $1.4 billion after giving effect to the estimated reduction in tax attributes as discussed above.

Emergence from Chapter 11 bankruptcy proceedings resulted in a change in ownership for purposes of IRC Section 382. The Company currently expects to apply rules under IRC Section 382(l)(5) that would allow the Company to mitigate the limitations imposed under the regulations with respect to the Company's remaining tax attributes. The Company's deferred tax assets and liabilities, prior to the valuation allowance, have been computed on such basis. Taxpayers who qualify for this provision may, at their option, elect not to apply the election. If the provision does not apply, the Company's ability to realize the value of its tax attributes would be subject to limitation and the amount of deferred tax assets and liabilities, prior to the valuation allowance, may differ. Additionally, under IRC Section 382(l)(5), an ownership change subsequent to the Company's emergence could severely limit or effectively eliminate its ability to realize the value of its tax attributes.

The Company has an available federal tax net operating loss carryforward estimated at approximately $1.4 billion as of December 31, 2021. These federal net operating loss carryforwards of approximately $278 million generated in tax years prior to 2018 will begin to expire in 2036. As a result of the Tax Cuts and Jobs Act, the 2018 through 2021 federal NOL carryforwards of $1.1 billion have no expiration. The Company also has state net operating loss carryovers of approximately $199 million that began to expire in 2022.

As of December 31, 2021, we had no liability for uncertain tax positions. As of December 31, 2020, the Company recorded a liability associated with uncertain tax positions of $3.8 million, which was settled in 2021. We recognize interest and penalties related to unrecognized tax benefits in the income tax expense line in the accompanying consolidated statement of operations, which are not material.

12. EARNINGS PER SHARE

Basic income or loss per share attributable to common stockholders is computed as (i) net income or loss less (ii) dividends paid to holders of New Preferred Stock less (iii) net income or loss attributable to participating securities divided by (iv) weighted average basic shares outstanding. Diluted net income or loss per share attributable to common stockholders is computed as (i) basic net income or loss attributable to common stockholders plus (ii) diluted adjustments to income allocable to participating securities divided by (iii) weighted average diluted shares outstanding. The "if-converted" method is used to determine the dilutive impact for the Company's convertible New Preferred Stock and the treasury stock method is used to determine the dilutive impact of unvested restricted stock.

There were no potential shares of common stock that were considered dilutive for the Successor Period, Predecessor Period, or the year ended December 31, 2020. There were 3.9 million shares that were considered anti-dilutive for the year ended December 31, 2019. There were 4.1 million shares of potential common shares issuable due to the Company's New Preferred Stock that were considered anti-dilutive for the Successor Period due to the Company's net loss. There were 0.1 million shares of restricted stock that were considered anti-dilutive during the Successor Period due to the Company's net loss.

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Net (loss) income	$ (112,829)	$ 250,994	$ (1,625,133)	$ (2,002,358)
Dividends on New Preferred Stock	(4,573)	—	—	—
Participating securities - New Preferred Stock(1)	—	—	—	—
Net (loss) income attributable to common stockholders	$ (117,402)	$ 250,994	$ (1,625,133)	$ (2,002,358)
Basic shares	20,545	160,834	160,231	160,341
Basic and dilutive EPS	$ (5.71)	$ 1.56	$ (10.14)	$ (12.49)

(1) New Preferred Stock represents participating securities because they participate in any dividends on shares of common stock on a *pari passu*, pro rata basis. However, New Preferred Stock does not participate in undistributed net losses.

13. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and NGL Derivative Instruments

The Company seeks to mitigate risks related to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, collars and various types of option contracts. These contracts allow the Company to mitigate the impact of declines in future natural gas, oil and NGL prices by effectively locking in floor price for a certain level of the Company's production. However, these hedge contracts also limit the benefit to the Company in periods of favorable price movements.

The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. Gulfport may enter into commodity derivative contracts up to limitations set forth in its New Credit Facility, 90% of its forecasted annual production for 2022 and 2023. The Company generally enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. The Company typically enters into commodity derivative contracts for the next 12 to 24 months. Gulfport does not enter into commodity derivative contracts for speculative purposes.

Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume. The prices contained in these fixed price swaps are based on the NYMEX Henry Hub for natural gas, the NYMEX WTI for oil and Mont Belvieu for propane.

The Company does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. The Company's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. Gulfport routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Below is a summary of the Company's open fixed price swap positions as of December 31, 2021.

	Index	Daily Volume	Weighted Average Price
Natural Gas		**(MMBtu/d)**	**($/MMBtu)**
2022	NYMEX Henry Hub	140,740	$ 2.88
2023	NYMEX Henry Hub	94,932	$ 3.41
Oil		**(Bbl/d)**	**($/Bbl)**
2022	NYMEX WTI	2,104	$ 66.23
2023	NYMEX WTI	1,000	$ 66.00
NGL		**(Bbl/d)**	**($/Bbl)**
2022	Mont Belvieu C3	3,378	$ 35.09
2023	Mont Belvieu C3	1,000	$ 33.77

The Company entered into costless collars based off the NYMEX WTI and Henry Hub oil and natural gas indices. Each two-way price collar has a set floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, the Company will cash-settle the difference with the counterparty. Below is a summary of the Company's open collars as of December 31, 2021.

	Index	Daily Volume	Weighted Average Floor Price	Weighted Average Ceiling Price
Natural Gas		(MMBtu/d)	($/MMBtu)	($/MMBtu)
2022	NYMEX Henry Hub	476,664	$ 2.64	$ 3.22
2023	NYMEX Henry Hub	85,000	$ 2.75	$ 4.25
Oil		(Bbl/d)	($/Bbl)	($/Bbl)
2022	NYMEX WTI	1,500	$ 55.00	$ 60.00

In the third quarter of 2019, the Company sold call options in exchange for a premium, and used the associated premiums received to enhance the fixed price for a portion of the fixed price natural gas swaps primarily for 2020. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, the Company pays its counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes. No payment is due from either party if the referenced settlement price is below the price ceiling. Below is a summary of the Company's open sold call options as of December 31, 2021.

	Index	Daily Volume	Weighted Average Ceiling Price
Natural Gas		(MMBtu/d)	($/MMBtu)
2022	NYMEX Henry Hub	152,675	$ 2.90
2023	NYMEX Henry Hub	507,925	$ 2.90
2024	NYMEX Henry Hub	162,000	$ 3.00

In addition, the Company entered into natural gas basis swap positions. As of December 31, 2021, the Company had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume	Weighted Average Fixed Spread
Natural Gas			(MMBtu/d)	($/MMBtu)
2022	Rex Zone 3	NYMEX Plus Fixed Spread	24,658	$ (0.10)
2022	ONG	NYMEX Plus Fixed Spread	7,397	$ 0.50
2023	Rex Zone 3	NYMEX Plus Fixed Spread	10,000	$ (0.22)

Balance sheet presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities, and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at December 31, 2021 and 2020 (in thousands):

	Successor	Predecessor
	December 31, 2021	December 31, 2020
Total short-term derivative instruments – asset	$ 4,695	$ 27,146
Total long-term derivative instruments – asset	$ 18,664	$ 322
Total short-term derivative instruments – liability	$ 240,735	$ 11,641
Total long-term derivative instruments – liability	$ 184,580	$ 36,604

Gains and losses

The following table presents the gain and loss recognized in net gain (loss) on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the Successor Period, Predecessor Period, and the years ended December 31, 2020, and 2019 (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Natural gas derivatives - fair value losses	$ (223,512)	$ (123,080)	$ (89,310)	$ 89,576
Natural gas derivatives - settlement (losses) gains	(300,172)	(3,362)	113,075	104,874
Total (losses) gains on natural gas derivatives	(523,684)	(126,442)	23,765	194,450
Oil and condensate derivatives - fair value losses	(5,128)	(6,126)	(2,952)	2,952
Oil and condensate derivatives - settlement (losses) gains	(9,720)	—	46,462	4,083
Total (losses) gains on oil and condensate derivatives	(14,848)	(6,126)	43,510	7,035
NGL derivatives - fair value losses	(5,322)	(4,671)	(461)	(7,541)
NGL derivatives - settlement (losses) gains	(12,965)	—	(142)	14,173
Total losses on NGL derivatives	(18,287)	(4,671)	(603)	6,632
Contingent consideration arrangement - fair value losses	—	—	(1,381)	243
Total (losses) gains on natural gas, oil and NGL derivatives	$ (556,819)	$ (137,239)	$ 65,291	$ 208,360

Offsetting of derivative assets and liabilities

As noted above, the Company records the fair value of derivative instruments on a gross basis. The following table presents the gross amounts of recognized derivative assets and liabilities in the consolidated balance sheets and the amounts that are subject to offsetting under master netting arrangements with counterparties, all at fair value.

	Successor		
	As of December 31, 2021		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 23,359	$ (20,265)	$ 3,094
Derivative liabilities	$ (425,315)	$ 20,265	$ (405,050)

	Predecessor		
	As of December 31, 2020		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 27,468	$ (25,730)	$ 1,738
Derivative liabilities	$ (48,245)	$ 25,730	$ (22,515)

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are with multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. None of the Company's derivative instrument contracts contain credit-risk related contingent features. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

14. RESTRUCTURING AND LIABILITY MANAGEMENT EXPENSES

In the third quarter of 2020 and fourth quarter of 2019, the Company announced and completed workforce reductions representing approximately10% and 13%, respectively, of its headcount. Restructuring charges related to the reduction in workforce primarily consisted of one-time employee-related termination benefits. Additionally, the Company incurred charges related to financial and legal advisors engaged to assist with the evaluation of a range of liability management alternatives during 2020 prior to the filing of the Chapter 11 Cases.

In the third quarter of 2021, the Company announced and completed a workforce reduction representing approximately3% of its headcount. Charges related to the reduction in workforce primarily consisted of one-time employee-related termination benefits.

The following table summarizes the expenses related to the Company's reductions in workforce as well as expenses incurred related to liability management efforts in the accompanying consolidated statements of operations for the Successor Period, Predecessor Period and the years ended December 31, 2020 and 2019 (in thousands):

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Reduction in workforce	$ 2,858	$ —	$ 1,460	$ 4,611
Liability management	—	—	29,387	—
Total restructuring and liability management expenses	$ 2,858	$ —	$ 30,847	$ 4,611

15. EQUITY INVESTMENTS

The Company had no investments accounted for by the equity method as of December 31, 2021. The following table summarizes the Company's equity investments for the Predecessor Period and the years ended December 31, 2020 and 2019 (in thousands):

	Carrying Value	Loss from Equity Method Investments		
	Predecessor	Predecessor		
	December 31, 2020	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Investment in Grizzly Oil Sands ULC	$ 24,816	$ 342	$ 377	$ 32,710
Investment in Mammoth Energy Services, Inc.	—	—	10,646	179,524
Other equity investments	—	—	32	(2,086)
Total equity investments	$ 24,816	$ 342	$ 11,055	$ 210,148

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings, owns an approximate24.5% interest in Grizzly, a Canadian unlimited liability company. As of December 31, 2021, Grizzly had approximately 830,000 acres under lease in the

Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. The Company has not paid any cash calls since its decision to cease funding further capital calls in 2019. Grizzly's functional currency is the Canadian dollar.

Effective as of the Emergence Date, the Company evaluated its investment in Grizzly and determined that the Company no longer has the ability to exercise significant influence over operating and financial policies of Grizzly. As such, the equity method of accounting for its investment was no longer applicable. As a result, the Company will use its previous carrying value of zero (as discussed below) as its initial basis and will subsequently measure at fair value while recording any changes in fair value in earnings.

As discussed in Note 3, the Company reduced the carrying value of its investment in Grizzly tozero upon the Emergence Date. The reduction in valuation was based upon the Company's new management's assessment of the investment and its priority for future funding in its portfolio. In particular, Grizzly's operations remained suspended, even with improvements in the pricing environment since its initial suspension in 2015. Additionally, the Company does not anticipate funding future capital calls, which will lead to further dilution of its equity ownership interest.

Mammoth Energy Services, Inc.

As discussed in Note 2, the Company's previously owned shares of the outstanding common stock of Mammoth Energy were used to settle Class 4A claims. The Company's investment carrying value was reduced to zero in the first quarter of 2020 due to the Company's share of cumulative net loss and impairments and the carrying value remained at zero through the Emergence Date.

16. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. Fair value measurements are classified and disclosed in one of the following categories:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Financial assets and liabilities

The following tables summarize the Company's financial assets and liabilities by valuation level as of December 31, 2021 and 2020:

	Successor		
	December 31, 2021		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 23,359	$ —
Contingent consideration arrangement	$ —	$ —	$ 5,800
Total assets	$ —	$ 23,359	$ 5,800
Liabilities:			
Derivative Instruments	$ —	$ 425,315	$ —

	Predecessor		
	December 31, 2020		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 27,468	$ —
Contingent consideration arrangement	$ —	$ —	$ 6,200
Total assets	$ —	$ 27,468	$ 6,200
Liabilities:			
Derivative Instruments	$ —	$ 48,245	$ —

The Company estimates the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

As discussed in Note 3, the water infrastructure sale included a contingent consideration arrangement. As of December 31, 2021, the fair value of the contingent consideration was $5.8 million, of which $1.0 million is included in prepaid expenses and other assets and $4.8 million is included in other assets in the accompanying consolidated balance sheets. The fair value of the contingent consideration arrangement is calculated using discounted cash flow techniques and is based on internal estimates of the Company's future development program and water production levels. Given the unobservable nature of the inputs, the fair value measurement of the contingent consideration arrangement is deemed to use Level 3 inputs. The Company has elected the fair value option for this contingent consideration arrangement and, therefore, records changes in fair value in earnings. As a result of a reduction in the future anticipated contingent consideration since the acquisition date, the Company recognized a gain of $0.4 million and a nominal gain for the Successor Period and the Predecessor Period, respectively, on changes in fair value of the contingent consideration, which is included in other expense (income) in the accompanying consolidated statements of operations. Settlements under the contingent consideration arrangement totaled $0.6 million and $0.2 million for the Successor Period and the Predecessor Period, respectively.

Non-financial assets and liabilities

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 5 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred were $0.2 million and $0.5 million for the Successor Period and the Predecessor Period, respectively.

The Company did not record any other than temporary impairments on its equity method investments during the Predecessor Period, Successor Period, or the year ended December 31, 2020. However, the Company recorded impairments on its investments during the year ended December 31, 2019. Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly as of December 31, 2020 was estimated using assumptions that represent Level 3 inputs.

Fair value of other financial instruments

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. See Note 6 for fair value of Company's long-term debt.

Chapter 11 Emergence and Fresh Start Accounting

On the Emergence Date, the Company adopted fresh start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon the adoption of fresh start accounting, the Company’s assets and liabilities were recorded at their fair values as of May 17, 2021. The inputs utilized in the valuation of the Company’s most significant asset, its oil and natural gas properties and related assets, included mostly unobservable inputs which fall within Level 3 of the fair value hierarchy. Such inputs included estimates of future oil and gas production from the Company’s reserve reports, commodity prices based on forward strip price curves (adjusted for basis differentials) as of May 17, 2021, operating and development costs, expected future development plans for the properties and discount rates based on a weighted-average cost of capital computation. The Company also recorded its asset retirement obligations at fair value as a result of fresh start accounting. The inputs utilized in valuing the asset retirement obligations were mostly Level 3 unobservable inputs, including estimated economic lives of oil and natural gas wells as of the Emergence Date, anticipated future plugging and abandonment costs and an appropriate credit-adjusted risk free rate to discount such costs. Refer to Note 3 for a detailed discussion of the fair value approaches used by the Company.

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company has conducted business activities with certain related parties.

As discussed in Note 2, the Company's previously owned shares of the outstanding common stock of Mammoth Energy were used to settle Class 4A claims in 2021. As of December 31, 2021, the Company held no shares of Mammoth Energy's outstanding common stock. As of December 31, 2020, the Company owned approximately 21.5% of Mammoth Energy's outstanding common stock. There were no material amounts and $0.6 million of services provided by Mammoth Energy that were included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2020 and 2019, respectively.

Approximately $3.1 million of services provided by Mammoth Energy were capitalized to oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets during the year ended December 31, 2020.

18. COMMITMENTS

Firm Transportation and Gathering Agreements

The Company has contractual commitments with midstream and pipeline companies for future gathering and transportation of natural gas from the Company's producing wells to downstream markets. Under certain of these agreements, the Company has minimum daily volume commitments. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it often can release it to other counterparties, thus reducing the cost of these commitments. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to future firm transportation and gathering agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, costs associated with utilized future firm transportation and gathering agreements are reflected in the Company's estimates of proved reserves.

A summary of these commitments at December 31, 2021, are set forth in the table below, excluding contracts recently rejected or in the process of being rejected as discussed in the *Litigation and Regulatory Proceedings* section in Note 19:

	(In thousands)
2022	$ 225,200
2023	222,683
2024	215,831
2025	137,082
2026	131,049
Thereafter	846,248
Total	$ 1,778,093

Future Sales Commitments

The Company has entered into various firm sales contracts with third parties to deliver and sell natural gas. The Company expects to fulfill its delivery commitments primarily with production from proved developed reserves. The Company's proved reserves have generally been sufficient to satisfy its delivery commitments during the three most recent years, and it expects such reserves will continue to be the primary means of fulfilling its future commitments. However, where the Company's proved reserves are not sufficient to satisfy its delivery commitments, it can and may use spot market purchases of third-party production to satisfy these commitments.

A summary of these commitments at December 31, 2021, are set forth in the table below:

	(MMBtu per day)
2022	4,000

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) plan under which eligible employees may contribute a portion of their total compensation up to the maximum pre-tax threshold through salary deferrals. The plan is considered a Safe Harbor 401(k) and provides a company match on 100% of salary deferrals that do not exceed4% of compensation in addition to a match of 50% of salary deferrals that exceed4% but do not exceed 6% of compensation. The Company may also make discretionary elective contributions to the plan. During the Successor Period, Predecessor Period, and the years ended December 31, 2020 and 2019, Gulfport incurred $0.7 million, $0.7 million, $2.6 million, and $2.9 million, respectively, in contributions expense related to this plan.

19. CONTINGENCIES

The Company is involved in litigation and regulatory proceedings including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. The Company's total accrued liabilities 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, its 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 their final liabilities may ultimately be materially different. In accordance with ASC Topic 450, *Contingencies*, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Litigation and Regulatory 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 May 17, 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.

As part of its Chapter 11 Cases and restructuring efforts as discussed in Note 2, the Company filed motions to reject certain firm transportation agreements between the Company and affiliates of TC Energy Corporation ("TC") and Rover Pipeline LLC ("Rover") or jointly as the "Pending Motions to Reject". The Pending Motions to Reject were removed to the United States District Court for the Southern District of Texas. While the Pending Motions to Reject are litigated, the Company isn't required to perform under these firm transportation agreements. During the third quarter of 2021, Gulfport finalized a settlement agreement with TC that was approved by the Bankruptcy Court on September 21, 2021. Pursuant to the settlement agreement, Gulfport and TC agreed that the firm transportation contracts between Gulfport and TC would be rejected without any further payment or obligation by Gulfport or TC, and TC assigned its damages claims from such rejection to Gulfport. In exchange, Gulfport agreed to make a payment of $43.8 million in cash to TC. The $43.8 million was paid to TC on October 7, 2021. Gulfport expects to receive distributions for a significant portion of such amounts through future distributions with respect to the assigned claims pursuant to Gulfport's Chapter 11 plan of reorganization that became effective in May 2021. Any future distributions will be recognized once received by Gulfport. In February 2022, Gulfport received an initial distribution of $11.5 million from the above mentioned claim. The timing and amount of any future distributions are not certain, and the total amount received will be impacted by the bankruptcy trustee's liquidation of Mammoth Energy shares and other bankruptcy claims. The Company believes that the Pending Motion to Reject with respect to Rover will be ultimately granted, and that the Company does not have any ongoing obligation pursuant to the contract; however, in the event that the Company is not permitted to reject the Rover firm transportation contract, it could be liable for demand charges, attorneys' fees and interest in excess of approximately $55 million.

The Company, along with a number of other oil and gas companies, has been named as a defendant in two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermilion on July 29, 2016 (together, the "Complaints"). The Complaints allege that certain of the defendants' operations violated the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder (the "CZM Laws") by causing substantial damage to land and waterbodies located in the coastal zone of the relevant Parish. The plaintiffs seek damages and other relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and interest. The case is stayed pending a ruling on plaintiff's motion to remand the lawsuit to state court. On September 9, 2021, the State of Louisiana and Cameron Parish dismissed all claims against Gulfport without prejudice.

In March 2020, Robert F. Woodley, individually and on behalf of all others similarly situated, filed a federal securities class action against the Company, David M. Wood, Keri Crowell and Quentin R. Hicks in the United States District Court for the Southern District of New York. The complaint alleges that the Company made materially false and misleading statements regarding the Company's business and operations in violation of the federal securities laws and seeks unspecified damages, the payment of reasonable attorneys' fees, expert fees and other costs, pre-judgment and post-judgment interest, and such other and further relief that may be deemed just and proper. On January 11, 2022, the court granted Gulfport's motion to dismiss and the case was closed by the court on February 14, 2022. The plaintiff's deadline to appeal the dismissal is March 16, 2022.

In September 2019, a stockholder of Mammoth Energy filed a derivative action on behalf of Mammoth Energy against members of Mammoth Energy's Board of Directors, including a director designated by the Company, and its significant stockholders, including the Company, in the United States District Court for the Western District of Oklahoma. The complaint alleges, among other things, that the members of Mammoth Energy's Board of Directors breached their fiduciary duties and violated the Securities Exchange Act of 1934, as amended, in connection with Mammoth Energy's activities in Puerto Rico following Hurricane Maria. The complaint seeks unspecified damages, the payment of reasonable attorney fees and legal expenses and interest and to force Mammoth Energy and its Board of Directors to make specified corporate governance reforms. On January 25, 2022, the court signed a final order and judgment dismissing all claims against Gulfport.

In December 2019, the Company filed a lawsuit against Stingray Pressure Pumping LLC, a subsidiary of Mammoth Energy ("Stingray"), for breach of contract and to terminate the Master Services Agreement for pressure pumping services, effective as of October 1, 2014, as amended (the "Master Services Agreement"), between Stingray and the Company. In March 2020, Stingray filed a counterclaim against the Company in the Superior Court of the State of Delaware. The counterclaim alleges that the Company has breached the Master Services Agreement. The counterclaim seeks actual damages, and Stingray filed claims in the Chapter 11 proceedings exceeding $80 million related to breach of contract damages, attorneys' fees and interest. In September 2021, Gulfport reached an agreement in principle with Stingray that fully resolves the litigation between the parties. Pursuant to the settlement, Stingray and Gulfport have agreed to drop all of the claims brought against each other in Delaware Court and Bankruptcy Court. On September 22, 2021, the parties announced to the bankruptcy court that all Stingray claims would be withdrawn. On December 15, 2021, the parties filed a Joint Stipulation and Agreed Order with the bankruptcy court resolving all claims.

In August 2020, Muskie filed an action against the Company in the Superior Court of the State of Delaware for breach of contract. The complaint alleges that the Company breached its obligation to purchase a certain amount of proppant sand each month or make designated shortfall payments under the Sand Supply Agreement, effective October 1, 2014, as amended (the "Sand Supply Agreement"), between Muskie and the Company, and seeks payment of unpaid shortfall payments, and Muskie filed a claim in the Chapter 11 proceedings for $3.4 million. On September 22, 2021, the parties announced to the bankruptcy court that an agreed claim for $3.1 million would resolve the matter. On December 15, 2021, the parties filed a Joint Stipulation and Agreed Order with the bankruptcy court resolving all claims.

In April 2020, Bryon Lefort, individually and on behalf of similarly situated individuals, filed an action against the Company in the United States District Court for the Southern District of Ohio Eastern Division. The complaint alleges that the Company violated the Fair Labor Standards Act ("FLSA"), the Ohio Wage Act and the Ohio Prompt Pay Act by classifying the plaintiffs as independent contractors and paying them a daily rate with no overtime compensation for hours worked in excess of 40 hours per week. The complaint seeks to recover unpaid regular and overtime wages, liquidated damages in an amount equal to six percent of all unpaid overtime compensation, the payment of reasonable attorney fees and legal expenses and pre-judgment and post-judgment interest, and such other damages that may be owed to the workers, and claims were filed in the Chapter 11 proceedings totaling $5.8 million. On October 1, 2021, the bankruptcy court approved the parties' settlement resolving all claims for a bankruptcy claim of approximately $0.7 million. The United States District Court for the Southern District of Ohio Eastern Division terminated the civil case on November 3, 2021.

The Company, along with other oil and gas companies, have been named as a defendant in J&R Passmore, LLC, individually and on behalf of all others similarly situated, in the United States District Court for the Southern District of Ohio on December 6, 2018. Plaintiffs assert their respective leases are limited to the Marcellus and Utica shale geological formations and allege that Defendants have willfully trespassed and illegally produced oil, natural gas, and other hydrocarbon products beyond these respective formations. Plaintiffs seek the full value of any production from below the Marcellus and Utica shale formations, unspecified damages from the diminution of value to their mineral estate, unspecified punitive damages, and the payment of reasonable attorney fees, legal expenses, and interest. On April 27, 2021, the Bankruptcy Court for the Southern District of Texas approved a settlement agreement in which the plaintiffs fully released the Company from all claims for amounts allegedly owed to the plaintiffs through the effective date of the Company's chapter 11 plan, which occurred on May 17, 2021. The plaintiffs are continuing to pursue alleged damages after May 17, 2021.

Business Operations

The Company is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for Gulfport and its subsidiaries. Gulfport and its subsidiaries have implemented various policies, programs, procedures, training and audits to reduce and mitigate environmental risks. The Company conducts periodic reviews, on a company-wide basis, to assess changes in their environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. The Company manages its 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, they may, among other things, exclude a property from the transaction, require the seller to remediate the property to their satisfaction in an acquisition or agree to assume liability for the remediation of the property.

Other Matters

Based on management's current assessment, they are of the opinion that no pending or threatened lawsuit or dispute relating to its business operations is likely to have a material adverse effect on their 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.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio and Oklahoma with sales to refineries, re-sellers such as marketers, and other end users. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation. At December 31, 2021, Gulfport held no cash in excess of insured limits in these banks.

During the Predecessor Period, three customers accounted for approximately 37% of the Company's total sales. During the Successor Period, two customers accounted for approximately 30% of the Company's total sales. During the year ended December 31, 2020, one customer accounted for approximately 12% of the Company's total sales. During the year ended December 31, 2019, one customer accounted for approximately 14% of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect on its natural gas, oil and condensate and NGL sales as alternative customers are readily available.

20. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

The Company is making the following supplemental disclosures of oil and gas activities, in accordance with the full cost method of accounting for its oil and gas exploration and development activities. The Company owns a 24.5% interest in Grizzly. However, Grizzly did not have any material activity or proved reserves in the years presented below. As such, amounts related to Grizzly have been omitted below.

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities (in thousands)

	Year ended December 31,	
	Successor	**Predecessor**
	2021	**2020**
Proved properties	$ 1,917,833	$ 9,359,866
Unproved properties	211,007	1,457,043
Total oil and natural gas properties	2,128,840	10,816,909
Accumulated depreciation, depletion, amortization and impairment	(277,331)	(8,778,759)
Net capitalized costs	$ 1,851,509	$ 2,038,150

Costs Incurred in Oil and Gas Property Acquisition and Development Activities (in thousands)

	Successor	**Predecessor**		
	Period from May 18, 2021 through December 31, 2021	**Period from January 1, 2021 through May 17, 2021**	**Year Ended December 31, 2020**	**Year Ended December 31, 2019**
Acquisition	$ 13,411	$ 3,922	$ 15,260	$ 37,598
Development	191,193	112,986	276,622	594,673
Exploratory	—	—	—	9,762
Total	$ 204,604	$ 116,908	$ 291,882	$ 642,033

Capitalized interest is included as part of the cost of oil and natural gas properties. The Company did not capitalize interest expense for the 2021 Predecessor Period, and capitalized $0.2 million, $0.9 million and $3.4 million during the Successor Period, 2020, 2019, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $8.0 million, $11.9 million, $25.0 million and $30.1 million during the Predecessor Period, the Successor Period, and the years ended December 31, 2020, and 2019, respectively, which were directly related to the acquisition, exploration and development of the Company's oil and natural gas properties.

Results of Operations for Producing Activities (in thousands)

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	Successor	Predecessor		
	Period from May 18, 2021 through December 31, 2021	Period from January 1, 2021 through May 17, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Revenues	$ 1,092,584	$ 410,276	$ 801,251	$ 1,354,766
Production costs	(274,428)	(192,959)	(537,609)	(620,412)
Depletion	(159,518)	(60,831)	(229,702)	(539,379)
Impairment	(117,813)	—	(1,357,099)	(2,039,770)
Income tax benefit (expense)	39	7,968	(7,290)	7,563
Results of operations from producing activities	$ 540,864	$ 164,454	$ (1,330,449)	$ (1,837,232)
Depletion per Mcf of gas equivalent (Mcfe)	$ 0.69	$ 0.45	$ 0.61	$ 1.08

Oil and Natural Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2021, 2020 and 2019 and changes in proved reserves during the last three years. The reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2021, 2020 and 2019, in accordance with guidelines of the SEC applicable to reserves estimates. The prices used for the 2021 reserve report are $66.55 per barrel of oil, $3.60 per MMbtu and $31.90 per barrel for NGL, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2020 and 2019 for reserve report purposes are $39.54 per barrel, $1.99 per MMbtu and $15.40 per barrel for NGL and $55.85 per barrel, $2.58 per MMbtu and $21.25 per barrel for NGL, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Natural Gas Equivalent (Bcfe)
Proved Reserves				
December 31, 2018 (Predecessor)	21	4,134	81	4,743
Purchases of reserves	—	—	—	—
Extensions and discoveries	4	997	13	1,097
Sales of reserves	(2)	(63)	—	(77)
Revisions of prior reserve estimates	(2)	(562)	(27)	(734)
Current production	(2)	(458)	(5)	(502)
December 31, 2019 (Predecessor)	18	4,048	62	4,528
Purchases of reserves	—	—	—	—
Extensions and discoveries	1	216	3	240
Sales of reserves	—	(74)	—	(75)
Revisions of prior reserve estimates	(4)	(1,564)	(23)	(1,725)
Current production	(2)	(345)	(4)	(380)
December 31, 2020 (Predecessor)	13	2,281	38	2,588
Purchases of reserves	—	—	—	—
Extensions and discoveries	2	617	11	695
Sales of reserves	—	—	—	—
Revisions of prior reserve estimates	2	913	9	982
Current production	(2)	(333)	(4)	(366)
December 31, 2021 (Successor)	16	3,478	54	3,898
Proved developed reserves				
December 31, 2019 (Predecessor)	8	1,757	30	1,984
December 31, 2020 (Predecessor)	7	1,358	22	1,527
December 31, 2021 (Successor)	8	1,928	31	2,165
Proved undeveloped reserves				
December 31, 2019 (Predecessor)	10	2,291	32	2,544
December 31, 2020 (Predecessor)	7	923	16	1,061
December 31, 2021 (Successor)	8	1,550	22	1,733

Totals may not sum or recalculate due to rounding.

In 2021, the Company experienced extensions of 694.6 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions, 352.2 Bcfe was attributable to the addition of 29 PUD locations in the Utica field, 342.2 Bcfe was attributable to the addition of 34 PUD locations in the SCOOP field. The Company experienced total upward revisions of approximately 982.2 Bcfe in estimated proved reserves, of which 889.2 Bcfe was the result of improved commodity prices. The 12-month average price for natural gas increased from $1.99 per MMBtu for 2020 to $3.60 per MMBtu for 2021, the 12-month average price for NGL increased from $15.40 per barrel for 2020 to $31.90 per barrel for 2021, and the 12-month average price for crude oil increased from $39.54 per barrel for 2020 to $66.55 per barrel for 2021. Upward revisions of 157.6 Bcfe were experienced from a combination of well performance, operating and development cost improvements and working interest changes. This was partially offset by a downward revision of 64.6 Bcfe, which was primarily a result of the exclusion of 4 PUD locations in the Company's Utica field when changes in the Company's schedule moved development of these PUD locations beyond five years of initial booking. The development plan change reflects the Company's commitment to capital discipline, funding future activities within cash flow and ongoing optimization of our development plan. Finally, during 2021, we sold approximately 0.2 Bcfe of proved oil and natural gas reserves through various sales of our non-operated interests in our other non-core assets.

In 2020, the Company experienced extensions of 239.8 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions, 150.6 Bcfe was attributable to the addition of 14 PUD locations in the Utica field, 87.8 Bcfe was attributable to the addition of eight PUD locations in the SCOOP field. The Company experienced total downward revisions of approximately 1.7 Tcfe in estimated proved reserves, of which 1,268.4 Bcfe was the result of commodity price changes. Commodity prices experienced volatility throughout 2020 and the 12-month average price for natural gas decreased from $2.58 per MMBtu for 2019 to $1.99 per MMBtu for 2020, the 12-month average price for NGL decreased from $21.25 per barrel for 2019 to $15.40 per barrel for 2020, and the 12-month average price for crude oil decreased from $55.85 per barrel for 2019 to $39.54 per barrel for 2020. An additional 720.3 Bcfe in downward revisions was a result of the exclusion of 48 PUD locations in the Utica field and 31 PUD locations in the SCOOP field, which was a result of changes in the Company's schedule that moved development of these PUD locations beyond five years of initial booking. The development plan change reflected the Company's commitment to capital discipline, funding future activities within cash flow and ongoing optimization of our development plan. Positive revisions of 263.8 Bcfe were experienced from a combination of operating and development cost improvements, well performance and working interest changes.

In 2019, the Company experienced extensions of 1.1 Tcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions, 793.5 Bcfe was attributable to the addition of 72 PUD locations in the Utica field, 302.9 Bcfe was attributable to the addition of 37 PUD locations in the SCOOP field. The Company experienced total downward revisions of approximately 733.8 Bcfe in estimated proved reserves, of which 347.2 Bcfe was a result of the exclusion of nine PUD locations in the Utica field and 22 PUD locations in the SCOOP field, which was a result of changes in the Company's schedule that moved development of these PUD locations beyond five years of initial booking. The development plan change reflects the Company's commitment capital discipline and funding future activities within cash flow. An additional 296.4 Bcfe in downward revisions was the result of commodity price changes. Commodity prices experienced volatility throughout 2019 and the 12-month average price for natural gas decreased from $3.10 per MMBtu for 2018 to $2.58 per MMBtu for 2019, the 12- month average price for NGL decreased from $32.02 per barrel for 2018 to $21.25 per barrel for 2019, and the 12-month average price for crude oil decreased from $65.56 per barrel for 2018 to $55.85 per barrel for 2019. The Company also experienced downward revisions of 90.2 Bcfe from a combination of working interest changes, optimization of well design in the current commodity price environment and well performance.

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

The following tables present the estimated future cash flows, and changes therein, from Gulfport’s proven oil and gas reserves as of December 31, 2021, 2020 and 2019 using an unweighted average first-of-the-month price for the period January through December 31, 2021, 2020 and 2019. The average gas prices used were $3.60, $1.99, and $2.58 for the periods ended December 31, 2021, 2020, and 2019, respectively. The average oil prices used were $66.55, $39.54, and $55.85, for the periods ended December 31, 2021, 2020, and 2019, respectively. The average NGL prices used were $31.90, $15.40, and $21.25, for the periods ended December 31, 2021, 2020, and 2019, respectively.

Year ended operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop proved undeveloped reserves are approximately $234.1 million in 2022, $184.0 million in 2023 and $178.7 million in 2024. Estimated future development costs include capital spending on major development projects. Gulfport believes cash flow from its operating activities, cash on hand and borrowings under its New Credit Facility will be sufficient to cover these estimated future development costs.

The assumptions used to derive the standardized measure of discounted future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes but should not be solely relied upon in evaluating Gulfport or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations and do not reflect cost savings of Company owned midstream operations on future operating expenses.
- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and condensate and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The following table summarizes estimated future net cash flows from natural gas and crude oil reserves (in millions):

	Year ended December 31,		
	Successor	Predecessor	
	2021	2020	2019
Future cash flows	$ 14,938	$ 4,079	$ 10,451
Future development and abandonment costs	(1,141)	(652)	(2,058)
Future production costs	(5,227)	(2,325)	(4,513)
Future production taxes	(336)	(137)	(333)
Future income taxes	(437)	—	—
Future net cash flows	7,797	965	3,547
10% discount to reflect timing of cash flows	(3,659)	(425)	(1,844)
Standardized measure of discounted future net cash flows	$ 4,138	$ 540	$ 1,703

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

The principal source of change in the standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below (in millions):

	Year ended December 31,		
	Successor	Predecessor	
	2021	2020	2019
Sales and transfers of oil and gas produced, net of production costs	$ (1,035)	$ (264)	$ (734)
Net changes in prices, production costs, and development costs	2,596	(954)	(1,372)
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	639	38	388
Previously estimated development costs incurred during the period	149	215	406
Revisions of previous quantity estimates, less related production costs	858	(255)	(321)
Sales of oil and gas reserves in place	(1)	(6)	(49)
Accretion of discount	54	170	298
Net changes in income taxes	(178)	—	425
Change in production rates and other	516	(109)	(319)
Total change in standardized measure of discounted future net cash flows	$ 3,598	$ (1,165)	$ (1,278)

21. SUBSEQUENT EVENTS

Natural gas, Oil and NGL Derivative Instruments

Subsequent to December 31, 2021 and as of February 25, 2022, the Company entered into the following natural gas, oil, and NGL derivative contracts:

Period	Type of Derivative Instrument	Index	Daily Volume(1)	Weighted Average Price
January 2023 - December 2023	Swaps	NYMEX WTI	1,000	$69.78
January 2023 - December 2023	Swaps	NYMEX Henry Hub	40,082	$3.56
January 2023 - December 2023	Swaps	Mont Belvieu C3	1,000	$36.33
January 2023 - December 2023	Basis Swaps	Rex Zone 3	10,000	$(0.20)

(1) Volumes for gas instruments are presented in MMBtu while oil and NGL volumes are presented in Bbls.

Release of Shares Held in Reserve

In January 2022, approximately 876 thousand shares held for reserve at December 31, 2021, were issued to certain claimants. As of February 25, 2022. approximately 62 thousand shares continue to be held in reserve and will be issued upon finalization of remaining claims.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and our Chief Financial Officer, and with participation of management, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2021, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that, as of December 31, 2021, our disclosure controls and procedures are effective.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

During the second quarter ended June 30, 2021, we added certain key controls related to our reorganization discussed in Note 2 of our consolidated financial statements.

Except as described above, there were no changes in our internal control over financial reporting during the year ended December 31, 2021, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the *2013 Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2*013 Internal Control-Integrated Framework,* management did not identify any material weaknesses in our internal control over financial reporting and concluded that out internal control over financial reporting was effective as of December 31, 2021.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2021 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2021, as stated in their accompanying report.

/s/ Timothy J. Cutt		/s/ William J. Buese	
Name:	Timothy J. Cutt	Name:	William J. Buese
Title:	Chief Executive Officer	Title:	Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of December 31, 2021 (Successor) and for the period from May 18, 2021 through December 31, 2021 (Successor) and the period from January 1, 2021 through May 17, 2021 (Predecessor), and our report dated March 1, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 1, 2022

ITEM 9B. OTHER INFORMATION

2022 Annual Meeting of Stockholders

The Board of Directors of the Company has determined that the Company's 2022 Annual Meeting of Stockholders (the "2022 Annual Meeting") will be held on June 14, 2022. The time and location of the 2022 Annual Meeting will be specified in the Company's 2022 proxy statement.

In accordance with the Company's Amended and Restated Bylaws (the "Bylaws"), any nomination by a stockholder of a person for election to the Board must be made by notice delivered to the Company not later than the close of business on March 16, 2022. Such notices of director nominations must comply with the requirements set forth in the Bylaws and the rules of SEC. Stockholders are urged to read the complete text of such notice provisions.

Any stockholder who, in accordance with Rule 14a-8 under the 1934 Act wishes to submit a proposal for inclusion in the proxy statement for the 2022 Annual Meeting must submit their proposal in writing, along with proof of eligibility, to the Company's principal executive offices in care of the Corporate Secretary by mail to 3001 Quail Springs Parkway, Oklahoma City, Oklahoma 73134. Proposal submissions must be received no later than the close of business on March 16, 2022, which the Company has determined to be a reasonable time before it expects to begin to print and send its proxy materials, to be considered timely. Such proposals also need to comply with the rules of the SEC regarding the inclusion of stockholder proposals in the Company's proxy materials, and may be omitted if not in compliance with applicable requirements.

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 and certain other senior 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 Gulfport pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than 120 days after the close of our fiscal year ended December 31, 2021 (the 2022 Proxy Statement).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2022 Proxy Statement.

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

The information called for by this Item 12 is incorporated herein by reference to the 2022 Proxy Statement.

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

The information called for by this Item 13 is incorporated herein by reference to the 2022 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2022 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Gulfport'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	Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1	Amended Joint Chapter 11 Plan of Reorganization of Gulfport Energy Corporation and its Debtor Subsidiaries.	8-K	001-19514	2.2	4/29/2021	
3.1	Amended and Restated Certificate of Incorporation of Gulfport Energy Corporation.	8-K	001-19514	3.1	5/17/2021	
3.2	Amended and Restated Bylaws of Gulfport Energy Corporation.	8-K	001-19514	3.2	5/17/2021	
4.2	1145 Indenture, dated as of May 17, 2021, by and among Gulfport Energy Corporation, UMB Bank, National Association, as trustee, and the guarantors party thereto (including the form of note attached thereto).	8-K	001-19514	4.1	5/17/2021	
4.3	4(a)(2) Indenture, dated as of May 17, 2021, by and among Gulfport Energy Corporation, UMB Bank, National Association, as trustee, and the guarantors party thereto (including the form of note attached thereto).	8-K	001-19514	4.2	5/17/2021	
10.1*+	Gulfport Energy Corporation 2021 Stock Incentive Plan.	8-K	001-19514	10.6	5/17/2021	
10.2*+	Form of Employee Restricted Stock Unit Award Agreement	10-Q	001-19514	10.7	8/9/2021	
10.3*+	Form of Director Restricted Stock Unit Award Agreement	10-Q	001-19514	10.8	8/9/2021	
10.4*+	Form of Performance-Based Restricted Stock Unit Award Agreement	10-Q	001-19514	10.9	8/9/2021	
10.5*+	CEO Agreement Amendment by and among Timothy Cutt and Gulfport, effective as of September 2, 2021.	8-K	001-19514	10.1	9/7/2021	
10.6*+	Employment Agreement by and among William Buese and Gulfport, effective as of May 17, 2021.	8-K	001-19514	10.5	5/17/2021	
10.7*+	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and Patrick K. Craine.	10-Q	000-19514	10.5	8/2/2019	
10.8	Employment Agreement dated November 13, 2020, by and between the Company and Michael Sluiter.	8-K	001-19514	10.4	11/16/2020	

10.9*	Third Amended and Restated Credit Agreement, dated as of October 14, 2021, by and among Gulfport Energy Corporation, as holdings, Gulfport Energy Operating Corporation, as the borrower, JPMorgan Chase Bank, N.A., the lenders party thereto, and the guarantors party thereto.	8-K	001-19514	10.1	10/14/2021	
10.12	Cooperation Agreement, dated as of May 17, 2021, by and among Gulfport Energy Corporation and Silver Point Capital, L.P.	8-K	001-19514	10.3	5/17/2021	
10.13	Registration Rights Agreement, dated as of May 17, 2021, by and among Gulfport Energy Corporation and the holders party thereto.	8-K	001-19514	10.2	5/17/2021	
10.14+	Form of Indemnification Agreement.	S-4	333-199905	10.1	11/6/2014	
21	Subsidiaries of the Registrant.					X
23.1	Consent of Netherland, Sewell & Associates, Inc.					X
31.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X
31.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X
32.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.					X
32.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.					X
99.1	Report of Netherland, Sewell & Associates, Inc.					X
101.INS	Inline XBRL Instance Document.					X
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.					X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.					X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.					X
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.					X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.					X

* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

+ Management contract, compensatory plan or arrangement.

Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately to the Securities and Exchange Commission.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 1, 2022

GULFPORT ENERGY CORPORATION

By: /s/ WILLIAM J. BUESE
William J. Buese
Chief Financial Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	March 1, 2022	By:	/s/ TIMOTHY J. CUTT **Timothy J. Cutt** **Chief Executive Officer and Chairman of the Board**
Date:	March 1, 2022	By:	/s/ DAVID WOLF **David Wolf** **Lead Independent Director**
Date:	March 1, 2022	By:	/s/ WILLIAM J. BUESE **William J. Buese** **Chief Financial Officer**
Date:	March 1, 2022	By:	/s/ GUILLERMO MARTINEZ **Guillermo Martinez** **Director**
Date:	March 1, 2022	By:	/s/ JASON MARTINEZ **Jason Martinez** **Director**
Date:	March 1, 2022	By:	/s/ DAVID REGANATO **David Reganato** **Director**

Exhibit 21

SUBSIDIARIES OF GULFPORT ENERGY CORPORATION

Name of Subsidiary	Jurisdiction of Organization
Gulfport Energy Operating Corporation	Delaware
Grizzly Holdings, Inc.	Delaware
Jaguar Resources LLC	Delaware
Puma Resources, Inc.	Delaware
Gator Marine, Inc.	Delaware
Gator Marine Ivanhoe, Inc.	Delaware
Westhawk Minerals LLC	Delaware
Gulfport Appalachia, LLC (formerly known as Gulfport Buckeye LLC)	Delaware
Gulfport Midstream Holdings, LLC	Delaware
Gulfport MidCon, LLC	Delaware
Mule Sky LLC	Delaware

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation (the "Form 10-K") of our report dated February 4, 2022 on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2021, located in the United States, information from our prior reserves reports referenced in the Form 10-K, and to all references to our firm included in the Form 10-K.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Senior Vice President

Houston, Texas
March 1, 2022

Exhibit 31.1

CERTIFICATION

I, Timothy J. Cutt, Chief Executive Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gulfport 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 statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

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

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

(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.

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

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

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

Date: March 1, 2022

/s/ Timothy J. Cutt

Timothy J. Cutt
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, William J. Buese, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gulfport 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 statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

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

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

(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.

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

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

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

Date: March 1, 2022

/s/ William J. Buese
William J. Buese
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, Timothy J. Cutt, Chief Executive Officer of Gulfport Energy Corporation (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2021 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Dated: March 1, 2022

/s/ Timothy J. Cutt
Timothy J. Cutt
Chief Executive Officer

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

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, William J. Buese, Chief Financial Officer of Gulfport Energy Corporation (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2021 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Dated: March 1, 2022

/s/ William J. Buese

William J. Buese
Chief Financial Officer

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

February 4, 2022

Mr. Timothy J. Cutt
Gulfport Energy Corporation
3001 Quail Springs Parkway
Oklahoma City, Oklahoma 73134

Dear Mr. Cutt:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2021, to the Gulfport Energy Corporation (Gulfport) 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 all of the proved reserves owned by Gulfport. 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 Gulfport'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 Gulfport interest in these properties, as of December 31, 2021, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	8,143.9	31,286.0	1,927,602.4	4,648,248.8	2,654,902.0
Proved Developed Non-Producing	0.0	0.2	496.1	776.2	415.4
Proved Undeveloped	8,096.8	22,480.6	1,549,986.6	3,585,205.5	1,660,322.7
Total Proved	16,240.7	53,766.8	3,478,085.1	8,234,234.9	4,315,637.2

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that 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 Gulfport's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Gulfport's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2021. For oil and NGL volumes, the average West Texas Intermediate spot price of $66.55 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.598 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $61.84 per barrel of oil, $31.93 per barrel of NGL, and $3.512 per MCF of gas.

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

Capital costs used in this report were provided by Gulfport and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for 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 Gulfport's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Gulfport 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 Gulfport 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 Gulfport, 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. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Gulfport, 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. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

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

/s/ Richard B. Talley, Jr.	/s/ Edward C. Roy III
By:	By:
Richard B. Talley, Jr., P.E. 102425	Edward C. Roy III, P.G. 2364
Senior Vice President	Vice President
Date Signed: February 4, 2022	Date Signed: February 4, 2022

RBT:MAG

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.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

(i) 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.

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

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

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

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

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

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

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

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

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

(20) *Production costs*.

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

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

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

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

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

extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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