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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2023

OR

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

For the transition period from to

Commission file number 001-41849

Mach Natural Resources LP

(Exact name of registrant as specified in its charter)

Delaware	**93-1757616**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
14201 Wireless Way, Suite 300, Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	(Zip Code)

(405) 252-8100
Registrant's telephone number, including area code

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common units representing limited partner interests	MNR	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 and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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 for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.☐

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

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The aggregate market value of common units held by non-affiliates of the registrant on March 15, 2024, based on the closing price of $19.12 for common units of the registrant as reported by the New York Stock Exchange, was approximately $191.2 million. The registrant has elected to use March 15, 2024 as the calculation date because the registrant's predecessor was a privately held company on June 30, 2023 (the last business day of the registrant's most recently completed second fiscal quarter).

The registrant had 95,000,000 common units outstanding as of March 15, 2024.

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GLOSSARY OF OIL AND GAS TERMS AND OTHER TERMS

The terms and abbreviations defined in this section are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"**Adjusted EBITDA**." Net income before (1) interest expense, (2) depreciation, depletion, amortization and accretion expense, (3) non-cash changes in derivative fair values, (4) equity-based compensation expense, (5) loss on contingent consideration and (6) gain on sale of assets.

"**Basin**." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"**Bbl**." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGL.

"**Bbtu**." One billion Btu.

"**Bcf**." Billion cubic feet.

"**BCE**" or "**Sponsor**." Investment funds managed by Bayou City Energy Management LLC and affiliates thereof.

"**BCE-Mach**." BCE-Mach LLC, a Delaware limited liability company.

"**BCE-Mach Credit Facility**." The reserve-based revolving credit facility that BCE-Mach entered into on September 2, 2022 with a syndicate of banks, including MidFirst Bank who serves as sole book runner and lead arranger, maturing in September 2026.

"**BCE-Mach II**." BCE-Mach II LLC, a Delaware limited liability company.

"**BCE-Mach II Credit Facility**." The reserve-based revolving credit facility that BCE-Mach II entered into with a syndicate of banks, including East West Bank, who serves as sole book runner and lead arranger.

"**BCE-Mach III**" or "**Predecessor**." BCE-Mach III LLC, a Delaware limited liability company.

"**BCE-Mach III Credit Facility**." The reserve-based revolving credit facility that the Predecessor entered into with a syndicate of banks, including MidFirst Bank, who serves as administrative agent and issuing bank.

"**BCE-Mach Aggregator**." BCE-Mach Aggregator LLC, a Delaware limited liability company.

"**BCE-Stack**." BCE-Stack Development LLC, a Delaware limited liability company.

"**Boe**." One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to one Bbl of oil.

"**British Thermal Unit**" or "**Btu**." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"**Code**." Internal Revenue Code of 1986, as amended.

"**Completion**." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"**Credit Agreements**." Together, the Term Loan Credit Agreement and the Revolving Credit Agreement.

"**Developed acreage**." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"**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 related 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.

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

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

"**Existing Owners**." Collectively refers to BCE and the Management Members.

"**Exploratory well**." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or 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 under Regulation S-X.

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

"**Field**." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

"**Formation**." A layer of rock which has distinct characteristics that differs from nearby rock.

"**Fracturing**" or "**fracture stimulation techniques**." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"**General partner agreement**." The Amended and Restated Limited Liability Company Agreement of Mach Natural Resources GP LLC.

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

"**Held by production**." Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or gas.

"**Holdco**." Mach Natural Resources Holdco LLC, a Delaware limited liability company.

"**Horizontal drilling**." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"**Hydraulic fracturing**." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"**Intermediate**." Mach Natural Resources Intermediate LLC, a Delaware limited liability company.

"**Lease operating expense**." The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

"**LNG**." Liquified natural gas.

"**LOE**." Lease operating expense.

"**Management Members**." Collectively refers to our current officers and employees who own indirect equity interests in the Mach Companies, including equity interests held by certain trusts affiliated with Mr. Ward.

"**Mach Companies**." Collectively refers to BCE-Mach, BCE-Mach II, and BCE-Mach III.

"**Mach Companies Class B Units**." Class B Units of the Mach Companies.

"**Mach Resources**." Mach Resources LLC.

"**MBbl**." One thousand barrels of crude oil, condensate or NGLs.

"**MBoe**." One thousand Boe.

"**MBoe/d**." One thousand Boe per day.

"**Mcf**." One thousand cubic feet of natural gas.

"**MMBtu**." One million Btu.

"**MMcf**." One million cubic feet of natural gas.

"**MMcf/d**." One million cubic feet of natural gas per day.

"**NGLs**." Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"**Net acres or net wells**" The percentage of total acres or wells an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"**November 2023 Credit Facility**." Refers to the new reserve-based revolving credit facility entered into by Holdco and MidFirst Bank on November 10, 2023.

"**NYMEX**." The New York Mercantile Exchange.

"**NYSE**." The New York Stock Exchange.

"**OGT**." ONEOK Gas Transmission.

"**OPEC +**." Organization of the Petroleum Exporting Countries.

"**Partnership agreement**." The Amended and Restated Agreement of Limited Partnership of Mach Natural Resources LP.

"**PCAOB**." The Public Company Accounting Oversight Board.

"**PDP**." Proved developed producing.

"**Pre-IPO Credit Facilities**." Collectively refers to the BCE-Mach Credit Facility, the BCE-Mach II Credit Facility and the BCE-Mach III Credit Facility.

"**Productive well**." A well that is 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 reserves**." Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. For a complete definition of proved crude oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"**Proved undeveloped reserves ("PUD")**." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years unless specific circumstances justify a longer time.

"**PV-10**." When used with respect to oil and natural gas reserves, PV-10 represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our Standardized Measure, the most comparable measure under GAAP. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"**Recompletion**." The process of re-entering an existing wellbore that is either producing or not producing and completing reservoirs in an attempt to establish or increase existing production.

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

"**Revolving Credit Agreement**." Refers to the senior secured revolving credit agreement, dated as of December 28, 2023, among the Company, the lenders party thereto, and MidFirst Bank as administrative agent.

"**SEC Pricing**." The oil and gas price parameters established by the current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"**Standardized Measure**." Standardized Measure is our standardized measure of discounted future net cash flows, which is prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation. However, our operations are subject to the Texas franchise tax. Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

"**Term Loan Credit Agreement**." Refers to the senior secured term loan credit agreement, dated as of December 28, 2023, among the Company, the lenders party thereto, Texas Capital Bank, as agent, and Chambers Energy Management, LP, as the arranger.

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

"**Wellbore**." The hole drilled by the bit that is equipped for oil and natural gas production on a completed well. Also called well or borehole.

"**Working interest**." The right granted to the lessee of a property to explore for and to produce and own oil and natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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

"**WTI**." West Texas Intermediate.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Annual Report contains or incorporates by reference information that includes or is based upon “forward-looking statements” within the meaning of Section 27A of the Securities Act , and Section 21E of the Exchange Act. All statements, other than statements of historical fact included in this Annual Report regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, words such as “may,” “assume,” “forecast,” “could,” “should,” “will,” “plan,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget” and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under “Risk Factors” in this Annual Report.

Forward looking statements may include statements about:

- our business strategy;
- our estimated proved reserves;
- our ability to distribute cash available for distribution and achieve or maintain certain financial and operational metrics;
- our drilling prospects, inventories, projects and programs;
- general economic conditions;
- actions taken by OPEC + as it pertains to the global supply and demand of, and prices for, oil, natural gas and NGLs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, leverage, liquidity and capital required for our development program;
- our pending legal or environmental matters;
- our realized oil and natural gas prices;
- the timing and amount of our future production of natural gas;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our marketing of natural gas;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- credit markets;
- our decline rates of our oil and natural gas properties;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil, natural gas and NGL. We disclose important factors that could cause our actual results to differ materially from our expectations as described under “Risk Factors” included in Item 1A of Part I of this Annual Report. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statement include:

- commodity price volatility;

- the impact of epidemics, outbreaks or other public health events, and the related effects on financial markets, worldwide economic activity and our operations;
- uncertainties about our estimated oil, natural gas and NGL reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- the concentration of our operations in the Anadarko Basin;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- lack of availability of drilling and production equipment and services;
- potential financial losses or earnings reductions resulting from our commodity price risk management program or any inability to manage our commodity risks;
- failure to realize expected value creation from property acquisitions and trades;
- access to capital and the timing of development expenditures;
- environmental, weather, drilling and other operating risks;
- regulatory changes, including potential shut-ins or production curtailments mandated by the Railroad Commission of Texas;
- competition in the oil and natural gas industry;
- loss of production and leasehold rights due to mechanical failure or depletion of wells and our inability to re-establish their production;
- our ability to service our indebtedness;
- any downgrades in our credit ratings that could negatively impact our cost of and ability to access capital;
- cost inflation;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or other with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and
- risks related to our ability to expand our business, including through the recruitment and retention of qualified personnel.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, our reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties materialize, or should underlying assumptions prove to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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.

RISK FACTOR SUMMARY

The following is a summary of the principal risks that could adversely affect our business, operations and financial results. Please refer to “Risk Factors” included in Item 1A of Part I of this Annual Report below for additional discussion of the risks summarized in this Risk Factor Summary.

Risks Related to Cash Distributions

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the payment of expenses, funding of development costs and establishment of cash reserves.
- The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Risks Related to Our Business

- Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.
- Currently, our producing properties are concentrated in the Anadarko Basin, making us vulnerable to risks associated with operating in a limited number of geographic areas.
- Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.
- The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- We depend on Mach Resources to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.
- The unavailability or high cost of drilling rigs, frac crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.
- Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.
- Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases such as COVID-19, or the threat thereof, and any related threats of recession and other economic repercussions could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.
- Our business is subject to climate-related risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and reduction in demand for oil and natural gas.
- Increased scrutiny of environmental, social, and governance (“ESG”) matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Risks Inherent in an Investment in Us

- Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.
- Our partnership agreement does not restrict the Sponsor (as defined below) from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.
- Our partnership agreement replaces our general partner's fiduciary duties to us and our unitholders with contractual standards governing its duties and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.
- Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.
- Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.
- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.
- We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.
- Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Part I

Items 1 and 2. Business and Properties

Business Overview

Mach Natural Resources LP (either individually or together with its consolidated subsidiaries, as the context requires, the “Company” or “Mach”) is an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Woodford, Meramec/Osage and Mississippi Lime formations. Our experience in the Anadarko Basin and these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments. We also own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure.

Corporate Reorganization

On October 25, 2023, the Company underwent a corporate reorganization (the “Corporate Reorganization”) whereby (a) the owners who directly held membership interests in the Mach Companies prior to the Offering (the “Existing Owners”) contributed 100% of their membership interests in each of the Mach Companies for a pro rata allocation of 100% of the limited partner interests in the Company with BCE-Mach III determined as the accounting acquirer of the net assets and operations of BCE-Mach and BCE-Mach II through a business combination, (b) the Company contributed 100% of its membership interests in the Mach Companies to Intermediate in exchange for 100% of the membership interests in Intermediate, and (c) Intermediate contributed 100% of its membership interests in the Mach Companies to Holdco in exchange for 100% of the membership interests in Holdco.

Our historical financial and operating data as of and for the year ended December 31, 2022, reflects BCE-Mach III LLC, the accounting predecessor of Mach Natural Resources LP. Our financial and operating data for the year ended December 31, 2023 includes BCE-Mach III for the entire period and BCE-Mach LLC and BCE-Mach II LLC from October 25, 2023, the effective date of the acquisition as a result of the Corporate Reorganization.

Initial Public Offering

On October 27, 2023, the Company completed the Offering of 10,000,000 common units at a price of $19.00 per unit to the public. The sale of Company’s common units resulted in gross proceeds of $190.0 million to the Company and net proceeds of $168.5 million, after deducting underwriting fees and offering expenses. The material terms of the Offering are described in the Company’s final prospectus, filed with the U.S. Securities and Exchange Commission (“SEC”) on October 26, 2023, pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended (the “Securities Act”).

The Company used $102.2 million of the proceeds to pay down the existing credit facilities of its operating subsidiaries (the “Pre-IPO Credit Facilities”) and $66.3 million of the proceeds to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis. After giving effect to the Offering and the transactions related thereto, the Company had 95,000,000 common units issued and outstanding.

Paloma Acquisition

On November 10, 2023, the Company entered into a purchase and sale agreement (the “Paloma PSA”) with Paloma Partners IV, LLC, a Delaware limited liability company, and its affiliated companies (the “Paloma Sellers”) pursuant to which the Company agreed to purchase from the Paloma Sellers certain interests in oil and gas properties, rights and related assets located in Blaine, Caddo, Canadian, Custer, Dewey, Grady, Kingfisher and McClain Counties, Oklahoma (the “Paloma Assets”).

On December 28, 2023, the Company completed the acquisition of the Paloma Assets (the “Asset Acquisition”) in accordance with the terms of the Paloma PSA for a purchase price of approximately $815,000,000 (subject to customary closing adjustment), in cash paid to the Paloma Sellers for the Paloma Assets. The Asset Acquisition provided for customary post-closing adjustments to the purchase price based on an effective date of September 1, 2023.

Information About Us

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

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

Properties

Our assets are located throughout Western Oklahoma, Southern Kansas and the panhandle of Texas and consist of approximately 4,600 gross operated PDP wells. Our average net daily production for the year ended December 31, 2023 was approximately 50 MBoe/d. Our wells are located almost exclusively in the Anadarko Basin, which has a more predictable production profile compared to less mature basins.

Additionally, we own a portfolio of midstream assets which support our leases, including ownership in four processing plants with combined processing capacity of 353 MMcf/d, along with 1,210 miles of gas gathering pipelines. Additionally, we own water infrastructure consisting of 880 miles of gathering pipeline and 55 disposal wells.

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. Funding sources for our acquisitions have included proceeds from borrowings under our revolving credit facilities, contributions from our equity partners and cash flow from operating activities. We spent approximately $302.8 million in 2023 on development costs and our budget for 2024 is between $250.0 million and $275.0 million. For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2024 is anticipated to focus on drilling Oswego wells given their high oil reserves and low breakeven costs.

During the year ended December 31, 2023, we spent approximately $261.6 million to drill 79.3 net wells and on related equipment, $28.8 million on remedial workovers and other capital projects, $12.4 million on midstream and other property and equipment capital projects, and $774.9 million on acquisitions.

Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2024 capital development programs from cash flow from operations.

Our development plan and capital budget are based on management's current expectations and assumptions about future events. While we consider these expectations and assumptions to be reasonable, they are subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated commodity prices, the availability of necessary equipment, infrastructure, drilling rigs, labor and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions and drilling and completion costs.

Oil and Natural Gas Reserves

Reserve Data

The information with respect to our estimated proved reserves based on SEC pricing presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following tables provide a summary of our estimated proved reserves and related PV-10 of proved reserves as of December 31, 2023 and 2022, using SEC pricing, based on evaluations prepared by Cawley, Gillespie & Associates Inc., our independent reserve engineer. See "— Preparation of reserve estimates" for the definitions of proved reserves and the technologies and economic data used in their estimation. Prices were adjusted for quality, energy content, transportation fees and market differentials, as applicable. The risk factors contained in this Annual Report including "Risk Factors —

Risks Related to Our Business — Oil and natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, cash available for distribution and results of operations, liquidity and our ability to meet our financial commitments or cause us to delay our planned capital expenditures" and "Risk Factors — Risks Related to Our Business — Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves," included in Item 1A of Part I of this Annual Report contain more information regarding the uncertainty associated with price and reserve estimates.

Summary Reserve Data

Our historical SEC reserves, PV-10 and Standardized Measure of proved reserves were calculated using oil and gas price parameters established by current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("SEC Pricing"). These prices were adjusted for differentials on a per-property basis, which may include local basis differential, fuel costs and shrinkage. All prices are held constant throughout the lives of the properties.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Item 7 of Part II of this Annual Report and "— Oil, Natural Gas and NGL Production Prices and Production Costs" in evaluating the material presented below.

	As of December 31,	
Reserve Data based on SEC Pricing(1)(2)	**2023**	**2022**
Proved Developed:		
Oil (MBbl)	49,629	29,984
Natural gas (MMcf)	909,372	527,369
Natural gas liquids (MBbl)	69,193	39,239
Total equivalent (MBoe)	270,384	157,117
PV-10 (in millions)(3)	$ 2,090	$ 2,343
Proved Undeveloped:		
Oil (MBbl)	25,944	18,596
Natural gas (MMcf)	197,102	102,251
Natural gas liquids (MBbl)	16,472	7,594
Total equivalent (MBoe)	75,266	43,232
PV-10 (in millions)(3)	$ 487	$ 611
Total Proved:		
Oil (MBbl)	75,573	48,580
Natural gas (MMcf)	1,106,474	629,620
Natural gas liquids (MBbl)	85,665	46,833
Total equivalent (MBoe)	345,650	200,349
PV-10 (in millions)(3)	$ 2,577	$ 2,954
Standardized Measure (in millions)(3)	$ 2,577	$ 2,954

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $93.67 per barrel for oil and $6.36 per MMbtu for natural gas at December 31, 2022 and $78.22 per barrel for oil and $2.64 per MMBtu for natural gas at December 31, 2023. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, fuel costs and shrinkage.

(2) The December 31, 2022 reserves reflect only the reserves of BCE-Mach III as the predecessor.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect

the timing of future cash flows. For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure" included in Item 7 of Part II of this Annual Report.

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2023 and 2022 included in this Annual Report are based on evaluations prepared by the independent petroleum engineering firm of Cawley, Gillespie & Associates Inc. in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering similar resources.

Under SEC rules, proved reserves are reserves 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 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data and well-test data.

Reserve engineering is, and must be recognized as, a subjective process of estimating volumes of economically recoverable 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 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 natural gas that are ultimately recovered. Estimates of economically recoverable natural gas and of future net cash flows 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 "Risk Factors" included in Item 1A of Part I of this Annual Report.

Internal Controls Over Reserve Estimates

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their preparation of reserve estimates. 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 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, natural gas and NGLs that are ultimately recovered. See "Risk Factors — Risks Related to Our Business — Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves" included in Item 1A of Part I of this Annual Report for more information. The reserves engineering group is responsible for the internal review of reserve estimates, and the technical person primarily responsible for overseeing the preparation of our reserve estimates has more than 16 years of experience in reserve engineering and has been with the Company since its inception. The reserves engineering group is independent of any of our operating areas. The reserves engineering group reviews the estimates with our third-party petroleum consultants, Cawley, Gillespie & Associates, an independent petroleum engineering firm.

Cawley, Gillespie & Associates is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2023, our proved undeveloped reserves were composed of 25,944 MBbls of oil, 197,102 MMcf of natural gas and 16,472 MBbls of NGLs for a total of 75,266 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs, for the year ended December 31, 2023 (in MBoe):

Balance, December 31, 2022(1)	43,232
Purchases of reserves	48,663
Revisions of previous estimates	(14,991)
Transfers to proved developed	(1,638)
Balance, December 31, 2023	75,266

(1) The balance at December 31, 2022 is that of BCE-Mach III as the predecessor, and purchases of reserves includes the acquisitions of reserves of BCE-Mach, BCE-Mach II, and Paloma.

Revisions of previous estimates of -14,991 MBoe during the year ended December 31, 2023 included the addition of 186 PUDs (23,014 MBoe) based on increasing our drilling activity within proven areas of development, and the deletion of 235 PUDs (-36,762 MBoe) due to changes in the corporate development plan and lower commodity prices (-115 Mboe). Additionally, changes to reflect current market conditions on lease operating expenses and product price differentials totaled -1,128 MBoe.

We converted 1,638 MBoe of any PUDs into proved developed reserves in 2023. Costs incurred relating to the development of all oil and natural gas reserves were $261.6 million during the year ended December 31, 2023.

We drilled 89 gross wells during 2023. We expect to drill or participate in the drilling of approximately 83 gross wells during 2024.

All of our PUD drilling locations are scheduled to be drilled within five years of December 31, 2023. We anticipate drilling and completing or participating in the drilling and completion of approximately 83 PUD locations during 2024, 72 during 2025, 66 during 2026, 40 during 2027 and 18 during 2028. These PUD locations relate to 75,266 MBoe of PUD reserves. Our development costs relating to the development of our PUDs at December 31, 2023 are projected to be approximately $210.0 million in 2024, $192.5 million in 2025, $225.2 million in 2026, $133.2 million in 2027 and $54.6 million in 2028 for a total of $815.5 million of future development costs. All of these PUD drilling locations are part of a development plan and a budget that is reviewed annually and adopted by management. We expect that the substantial cash flow generated by our existing wells, in addition to availability under the Revolving Credit Agreement, will be sufficient to fund our drilling program, maintenance capital expenditures and PUD conversion into proved developed reserves in accordance with our development schedule. Please see "Risk Factors — Risks Related to Our Business — Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." included in Item 1A of Part I of this Annual Report.

Oil, Natural Gas and NGL Production Prices and Production Costs

Production and Price History

We currently only have production in the Anadarko Basin. The following table sets forth information regarding our production volumes and realized prices for the periods indicated.

	Year Ended December 31,		
	2023	2022	2021
Net Production Volumes:			
Oil (MBbl)	5,445	4,801	2,777
Natural gas (MMcf)	59,378	47,561	32,313
NGLs (MBbl)	3,068	2,812	2,180
Total (MBoe)	18,409	15,539	10,343
Average daily production (MBoe/d)	50.44	42.57	28.34
Average Realized Prices (excluding effects of realized derivatives):			
Oil (MBbl)	$ 77.57	$ 93.43	$ 68.35
Natural gas (MMcf)	$ 2.52	$ 6.34	$ 4.08
NGLs (MBbl)	$ 24.52	$ 39.27	$ 34.80
Average Realized Prices (including effects of realized derivatives):			
Oil (MBbl)	$ 76.51	$ 82.94	$ 49.69
Natural gas (MMcf)	$ 2.76	$ 5.49	$ 3.79
NGLs (MBbl)	$ 24.52	$ 39.27	$ 34.80

Operating Data

The following table sets forth information regarding our revenues and operating expenses for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
	2023	2022	2021
Revenues:			
Oil	$ 422,312	$ 448,567	$ 189,827
Natural gas	149,795	301,423	131,819
Natural gas liquids	75,245	110,398	75,854
Total oil, natural gas, and NGL sales	647,352	860,388	397,500
Gain (loss) on oil and natural gas derivatives, net	57,272	(67,453)	(67,549)
Midstream revenue	26,328	44,373	31,883
Product sales	31,357	100,106	30,663
Total revenues	$ 762,309	$ 937,414	$ 392,497
Operating Costs and Expenses:			
Gathering and processing expense	$ 39,449	$ 47,484	$ 27,987
Lease operating expense	127,602	95,941	45,391
Production taxes	31,882	47,825	21,165
Midstream operating expense	10,873	15,157	12,248
Cost of product sales	28,089	94,580	28,687
Depreciation, depletion, amortization and accretion expense – oil and natural gas	131,145	84,070	37,537
Depreciation and amortization expense – other	6,472	4,519	3,148
General and administrative	27,653	25,454	60,927
Operating Costs and Expenses (per Boe):			
Gathering and processing expense	$ 2.14	$ 3.06	$ 2.71
Lease operating expense	$ 6.93	$ 6.17	$ 4.39
Production taxes (% of oil, natural gas and NGL sales)	4.9 %	5.6 %	5.3 %
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 7.12	$ 5.41	$ 3.63
Depreciation and amortization expense – other	$ 0.35	$ 0.29	$ 0.30
General and administrative	$ 1.50	$ 1.64	$ 5.89

Developed and Undeveloped Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2023:

	Developed Acres	Undeveloped Acres	Total Acres
Gross	2,767,909	21,929	2,789,838
Net	1,060,907	16,308	1,077,215

Undeveloped Acreage Expirations

The following table sets forth the number of total net undeveloped acres as of December 31, 2023 that will expire in 2024, 2025, 2026, 2027 and 2028 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed. This undeveloped acreage includes approximately

928 acres that PUD locations have been assigned to; however, within 2024, we have since drilled or will have scheduled drilling on nearly all of these acres.

	2024	2025	2026	2027	2028
Total	2,668	7,906	2,794	562	—

All of our acreage is located in the Anadarko Basin.

Drilling Results

The table below sets forth the results of our operated drilling activities for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Year Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Operated:						
Productive	91	81.0	88	76.0	20	17.7
Dry holes	—	—	—	—	—	—
Total	91	81.0	88	76.0	20	17.7
Development Wells Non-Operated:						
Productive	19	2.6	14	1.7	—	—
Dry holes	—	—	—	—	—	—
Total	19	2.6	14	1.7	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total	—	—	—	—	—	—
Total Wells:						
Productive	110	83.6	102	77.7	20	17.7
Dry holes	—	—	—	—	—	—
Total	110	83.6	102	77.7	20	17.7

The following table sets forth information regarding our drilling activities as of December 31, 2023, including with respect to our operated wells we have begun drilling and those which are drilled and awaiting completion.

	As of December 31, 2023	
	Gross	Net
Drilling	3	2.9
Drilled and Awaiting Completion	2	2.0

As of December 31, 2023, the Company was in process of drilling 3 gross wells (2.9 net) and had finished drilling and was completing or awaiting completion on 2 gross wells (2.0 net). As of December 31, 2023, the Company had no material ongoing non-operated drilling and completion activities.

As of December 31, 2023, we were not a party to any long-term drilling rig contracts.

Productive Wells

As of December 31, 2023, we owned interests in the following number of productive wells:

	Productive Wells		
	Gross	Net	Average Working Interest
Natural gas	5,669	2,184	39 %
Oil	4,021	1,876	47 %
Total	9,690	4,060	42 %

Marketing and Customers

We market production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

For the years ended December 31, 2023, 2022 and 2021, purchases by the following companies exceeded 10% of our receipts from oil, natural gas, and NGL sales:

	Year Ended December 31,		
	2023	2022	2021
Hinkle Oil and Gas Inc.	*	31.5 %	13.3 %
NextEra Energy Marketing, LLC	12.9 %	17.0 %	20.2 %
Philips 66 Company	52.6 %	16.9 %	33.5 %
ONEOK Hydrocarbon L.P.	10.4 %	*	13.9 %

* Purchaser did not account for greater than 10% of oil, natural gas, and NGL sales for the year.

Gathering & Processing Agreements and Firm Transportation

In some areas, we own our own gathering and/or processing assets but in other areas we incur gathering and processing expense under various gathering and/or processing agreements with third-party midstream providers. Only one of our gathering and/or processing agreements includes minimum volume commitments.

We are party to four firm transportation agreements to assist in transporting our natural gas from processing plants to various markets. Any unutilized capacity is monetized if market conditions allow by releasing the capacity to others or transporting third party gas. For the years ended December 31, 2023, 2022 and 2021 we incurred approximately $1.0 million, $0.4 million and $0.3 million, respectively, of transportation charges under these agreements.

The following table sets forth certain information regarding certain of our firm transportation agreements:

	Midcontinent Express	Southern Star	OGT – Lincoln	OGT – Elmore City
Daily Quantity (MMBtu)	25,000	150,000	25,000	5,000
Average Rate (per MMBtu)	$ 0.33	$ 0.09	$ 0.17	$ 0.05
Expiration	July 31, 2024	January 1, 2025	May 31, 2024	October 31, 2024

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in evaluating and bidding for oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of developing natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Seasonality of Business

Generally, demand for natural gas, oil and NGL decreases during the spring and fall months and increases during the summer and winter months. However, certain natural gas and NGL markets utilize storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. In addition, seasonal anomalies such as mild winters or mild summers can have a significant impact on prices. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages, increased costs or delay operations.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Legislative and Regulatory Environment

Our natural gas, oil and NGL exploration, development, production and related operations and activities are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with such rules and regulations can result in administrative, civil or criminal penalties, compulsory remediation and imposition of natural resource damages or other liabilities. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, we believe these obligations generally do not impact us differently or to any greater or lesser extent than they affect other operators in the natural gas and oil industry with similar operations and types, quantities and locations of production.

Regulation of Production

In many states, oil and natural gas companies are generally required to obtain permits for drilling operations, provide drilling bonds, file reports concerning operations and meet other requirements related to the exploration, development and production of natural gas, oil and NGL. Such states also have statutes and regulations addressing conservation matters, including provisions for unitization or pooling of natural gas and oil interests, rights and properties, the surface use and restoration of properties upon which wells are drilled and disposal of water produced or used in the drilling and completion process. These regulations include the establishment of maximum rates of production from natural gas and oil wells, rules as to the spacing, plugging and abandoning of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production, as well as rules governing the surface use and restoration of properties upon which wells are drilled.

These laws and regulations may limit the amount of natural gas, oil and NGL that can be produced from wells in which we own an interest and may limit the number of wells, the locations in which wells can be drilled, or the method of drilling wells. Additionally, the procedures that must be followed under these laws and regulations may result in delays in obtaining permits and approvals necessary for our operations and therefore our expected timing of drilling, completion and production may be negatively impacted. These regulations apply to us directly as the operator of our leasehold. The failure to comply with these rules and regulations can result in substantial penalties.

Regulation of Sales and Transportation of Liquids

Sales of condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress has enacted price controls in the past and could reenact such controls in the future.

Our sales of NGLs are affected by the availability, terms and cost of transportation. The transportation of NGLs in common carrier pipelines is subject to rate and access regulation. The Federal Energy Regulatory Commission (“FERC”) regulates interstate oil, NGL and other liquid pipeline transportation rates under the Interstate Commerce Act. In general, interstate liquids pipeline rates are set using an annual indexing methodology, however, a pipeline may also use a cost-of-service approach, settlement rates or market-based rates in certain circumstances.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of liquids transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of Natural Gas Policy Act of 1978 (the “NGPA”) and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 (“NGA”) and the NGPA, and by regulations and orders promulgated by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005 (the “EPAct of 2005”) amended the NGA and NGPA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EPAct of 2005 also provided FERC with the power to assess civil penalties of up to $1,000,000 per day (adjusted annually for inflation) for violations of the NGA and NGPA. As of 2023, the new adjusted maximum penalty amount is $1,496,035 per violation, per day. The civil penalty provisions are applicable to entities that engage in the sale and transportation of natural gas for resale in interstate commerce.

On January 19, 2006, FERC issued Order No. 670, implementing the anti-market manipulation provision of the EPAct of 2005, and subsequently denied rehearing. The resulting rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-FERC jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services. FERC also interprets its authority to reach otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704, described below. However, in October 2022, the Fifth Circuit ruled that FERC's jurisdiction to regulate market manipulation is limited to interstate transactions only and does not reach intrastate natural gas transactions.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. As a result of these orders, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including oil and natural gas producers, gatherers and marketers, are now required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance provided by FERC. Market participants must also indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transportation services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering facilities gathering function or a jurisdictional transportation function, FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transportation facilities as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transportation services and federally unregulated gathering services could be the subject of ongoing litigation, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

In addition, the pipelines in the gathering systems on which we rely may be subject to regulation by the U.S. Department of Transportation. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. Over the past several years PHMSA has taken steps to expand the regulation of rural gathering lines and impose a number of reporting and inspection requirements on regulated pipelines, and additional requirements are expected in the future. On November 15, 2021, PHMSA released a final rule that expands the definition of regulated gathering pipelines and imposes safety measures on certain currently unregulated gathering pipelines. The final rule also imposes reporting requirements on all gathering pipelines and specifically requires operators to report safety information to PHMSA. The future adoption of laws or regulations that apply more comprehensive or stringent safety standards could increase the expenses we incur for gathering service.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical and financial sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the EPAct of 2005 and by the Commodity Futures Trading Commission ("CFTC") under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act, and regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity as well as certain disruptive trading practices. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. As such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC, PHMSA, the CFTC, or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC, PHMSA, the CFTC, or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other oil and natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters Generally

Our operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing environmental protection, occupational safety and health, and the release, discharge or disposal of materials into the environment, some of which carry substantial administrative, civil and criminal penalties for failure to comply. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), the CWA and the CAA. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants, and other matters. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling, and production operations; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit construction or drilling activities in sensitive areas such as wilderness, wetlands, frontier and other protected areas; require investigatory or remedial actions to prevent or mitigate pollution conditions caused by our operations; impose obligations to reclaim and abandon well sites and pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties, loss of leases, the imposition of investigatory or remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. It is possible that, over time, environmental regulation could evolve to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or reinterpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities or waste handling, storage, transport, disposal, or remediation requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our business, there can be no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes

CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These classes of persons, or, as termed in CERCLA, potentially responsible parties, include the current and past owners or operators of a disposal site or site where the release occurred and anyone who disposed or arranged for the disposal of the hazardous substances found at such sites. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA and other environmental laws but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect our business operations. While petroleum and crude oil fractions are generally not considered hazardous substances under CERCLA and its analogues because of the so-called “petroleum exclusion,” adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

We also generate solid and hazardous wastes that may be subject to the requirements of the Resource Conservation and Recovery Act, as amended (“RCRA”), and analogous state laws. RCRA regulates the generation, handling, storage, treatment, transport and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes “drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy” from regulation as hazardous wastes. With the approval of the EPA, individual states can administer some or all of the provisions of RCRA and some states have adopted their own, more stringent requirements. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as “hazardous wastes,” which would make such wastes subject to much more stringent handling, disposal and clean-up requirements. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes are determined to have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease or operate numerous properties that may have been used by prior owners or operators for oil and natural gas development and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations where such substances have been taken for recycling or disposal. In addition, some of our properties may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and/or analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, also known as the CWA, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other natural gas wastes, into or near waters of the United States or state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The discharge of dredge and fill material into regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”). The EPA and the Corps issued a final rule on the federal jurisdictional reach over waters of the United States in 2015, which never took effect before being replaced by the Navigable Waters Protection Rule (the “NWPR”) in 2020. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. In January 2023, the EPA and the Corps issued a final rule that based the definition of WOTUS on the pre-2015 definition. Separately, in May 2023, the U.S. Supreme Court’s recent decision in *Sackett v. EPA* invalidated the prior test used by the EPA to determine whether wetlands qualify as navigable waters of the United States, and in September 2023, the EPA and the Corps published a final rule to align the definition of “waters of the United States” with the U.S. Supreme Court’s decision in *Sackett v. EPA*. To the extent a stay of recent rules or the implementation of a revised rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits, including for dredge and fill activities in wetland areas. In addition, in an April 2020 decision defining the scope of the CWA that was issued days after the NWPR was published, the U.S. Supreme Court held that, in certain cases, discharges from a point source to a WOTUS through groundwater require a permit if the discharge is the "functional equivalent" of a direct discharge. The Court rejected the EPA and the Corps' assertion that groundwater should be totally excluded from the CWA. In November 2023, the EPA issued draft guidance describing the functional equivalent analysis and the information that should be used to determine which discharges through groundwater may require a permit. If finalized, the guidance could subject previously unregulated discharges to CWA permit requirements. As a result, future implementation is uncertain at this time.

The process for obtaining permits also has the potential to delay our operations. For example, in April 2020, the U.S. District Court for the District of Montana vacated Nationwide Permit ("NWP") 12, the general permit issued by the Corps for pipelines and utility projects. On May 11, 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The Corps appealed the decision to the U.S. Court of Appeals for the Ninth Circuit. On July 6, 2020, the U.S. Supreme Court granted in part and denied in part the Corps' application for stay of the order issued by the district court. The U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. On January 5, 2021, the Corps released the final version of a rule renewing twelve of its NWPs, including NWP 12. The new rule, which took effect on March 15, 2021, splits NWP 12 into three parts; NWP 12 will continue to be available to oil and gas pipelines. On March 28, 2022, the Corps published a notice announcing that it is undertaking formal review of NWP 12 and sought public comments. The Corps' review has concluded, and a notice of proposed rulemaking to revise certain NWPs, including NWP 12, is expected in 2024. Any further changes to NWP 12 could have an impact on our business. We cannot predict at this time how the new Corps rule will be implemented, because permits are issued by the local Corps district offices. If new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of CWA compliance, such projects could be significantly delayed. Additionally, spill prevention, control and countermeasure plans, also referred to as "SPCC plans," are required by federal law in connection with on-site storage of significant quantities of oil. Compliance may require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak.

Safe Drinking Water Act

The SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans. The SDWA also regulates saltwater disposal wells under the Underground Injection Control Program. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of "underground injection," but disposal of hydraulic fracturing fluids and produced water or their injection for enhanced oil recovery is not excluded. In 2014, the EPA issued permitting guidance governing hydraulic fracturing with diesel fuels. While we do not currently use diesel fuels in our hydraulic fracturing fluids, we may become subject to federal permitting under SDWA if our fracturing formula changes.

Air Emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and other requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion. Further, in June 2016, the EPA also finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. These rules could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements.

State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the CAA that require the reduction of volatile organic compound and methane emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In addition, the regulations place new requirements to detect and repair volatile organic compound and methane at certain well sites and compressor stations.

In November 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule imposes emissions reduction standards on both new and existing sources in the oil and natural gas industry, expands the scope of CAA regulation by making regulations in Subpart OOOOa more stringent and creating a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA, and imposes emissions reductions targets to meet the stated goals of the U.S. federal administration. In November 2022, the EPA issued the proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as “super emitters.” In December 2023, the EPA announced a final rule, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane emissions from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas projects and increase our costs of development, which costs could be significant.

Climate Change

More stringent laws and regulations relating to climate change and greenhouse gases (“GHGs”) may be adopted and could cause us to incur material expenses to comply with such laws and regulations. These requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. The EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations.

We cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility. There are also a number of state and regional efforts to regulate emissions of methane from new and existing sources within the oil and natural gas source category. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, and increased frequency of maintenance and repair activities to address emissions leakage at certain well sites and compressor stations, and also may require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and the current U.S. presidential administration has taken and supported action aiming to limit GHG emissions. The $1 trillion legislative infrastructure package passed by Congress in November 2021 included a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events, and clean energy and transportation investments. In addition, in August 2022, President Biden signed the Inflation Reduction Act into law, which focuses on incentivizing the reduction of methane emissions and would impose a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives. At the international level, in February 2021, the current administration announced reentry of the U.S. into the Paris Agreement (an international agreement from the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement for signatory countries to nationally determine their contributions and set GHG emission reduction goals) along with a new “nationally determined contribution” for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. Further, at the 28th Conference of the Parties to the United Nations Framework Convention on Climate Change, member countries entered into an agreement that calls for actions toward achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts toward the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems.

In August 2022, President Biden signed the Inflation Reduction Act into law, which focuses on incentivizing the reduction of methane emissions and would impose a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives. The Inflation Reduction Act amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program, which requires the EPA to impose a “waste emissions charge” on certain natural gas and oil sources that are already required to report under the EPA’s Greenhouse Gas Reporting Program. To implement the program, the Inflation Reduction Act requires revisions to GHG reporting regulations for petroleum and natural gas systems (Subpart W) by 2024. In July 2023, the EPA proposed to expand the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities, as required by the Inflation Reduction Act. Among other things, the proposed rule would expand the emissions events that are subject to reporting requirements to include "other large release events" and apply reporting requirements to certain new sources and sectors. The rule is currently expected to be finalized in 2024 and become effective on January 1, 2025 in advance of the deadline for GHG reporting for 2024 (March 2025). In January 2024, the EPA proposed a rule implementing the Inflation Reduction Act's methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the Inflation Reduction Act. The methane emissions charge imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 in 2026.

Separately, many U.S. state and local leaders and foreign governments have intensified or stated their intent to intensify efforts to support international climate commitments and treaties and have developed programs that are aimed at reducing GHG emissions, such as by means of cap and trade programs, carbon taxes, encouraging the use of renewable energy or alternative low-carbon fuels, or imposing new climate-related reporting requirements. Cap and trade programs, for example, typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

Financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, the Federal Reserve in 2020 announced that it joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In 2022, the Federal Reserve launched a pilot climate scenario analysis exercise to learn about certain large banking organizations' climate risk-management practices and challenges and help ensure that supervised institutions are appropriately managing material financial risks related to climate change. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, on March 6, 2024, the SEC adopted new rules regarding the enhancement and standardization of climate-related disclosures for investors (the "SEC Climate Rules"). The SEC Climate Rules will require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about material climate-related risks; the registrant's governance of climate-related risks and relevant risk management processes; material climate-related targets and goals; and certain financial effects resulting from severe weather events and other natural conditions in a note to their audited financial statements (subject to de minimis thresholds). Larger registrants will also be required to disclose information about material Scope 1 and 2 greenhouse gas emissions, which will be subject to a phased-in assurance requirement. We are currently evaluating the impact of the SEC Climate Rules and there remains uncertainty as to whether these rules will withstand pending and future legal challenges. In addition, regulations requiring the disclosure of climate-related information have also been enacted or proposed at the state-level, including in California.

Further, in January 2024, President Biden announced a temporary pause on pending decisions on exports of LNG to non-free trade agreement countries until the Department of Energy can update the underlying analyses for authorizations, including an assessment of the impact of GHG emissions.

Any legislation or regulatory programs aimed at reducing GHG emissions, addressing climate change more generally, or requiring the disclosure of climate-related information could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce or otherwise have an adverse effect on our business, financial condition and results of operations.

Hydraulic Fracturing

Hydraulic fracturing is a common practice that is used to stimulate production of oil and/or natural gas from low permeability subsurface rock formations and is important to our business. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the hydrocarbon-bearing rock formation and stimulate production of hydrocarbons. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is primarily regulated at the state level, typically by state natural gas commissions, but the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels.

In addition, there are heightened concerns by the public about hydraulic fracturing causing damage to aquifers and there is potential for future regulation to address those concerns. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances.

At the state level, several states have adopted or are considering legal requirements that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. Local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential legislation or regulation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Oil Pollution Act

The Oil Pollution Act of 1990 (the “OPA”) establishes strict liability for owners and operators of facilities that are the source of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties, including owners and operators of certain facilities from which oil is released, related to the prevention of oil spills and liability for damages resulting from such spills. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of an environmental assessment and, if necessary, an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action have the potential to significantly impact the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, may increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases. In July 2020, the Council on Environmental Quality (“CEQ”) revised NEPA’s implementing regulations to make the NEPA process more efficient, effective and timely. The rule required federal agencies to develop procedures consistent with the new rule within one year of the rule’s effective date (which was extended to two years in June 2021). These regulations are subject to ongoing litigation in several federal district courts, and in October 2021, CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Phase I of the CEQ’s rulemaking process was finalized in April 2022, and generally restored provisions that were in effect prior to 2020. In July 2023, the Council on Environmental Quality proposed a Phase 2 rule that would accelerate NEPA reviews while maintaining consideration of relevant environmental, climate change and environmental justice effects. The final rule is expected in April 2024. However, several states and environmental groups have filed challenges to this rulemaking, and CEQ’s amendments are subject to reconsideration and may be subject to reversal or change under the Biden administration. Further, the Infrastructure and Investment Jobs Act signed into law in November 2021, codified some of the July 2020 amendments in statutory text. These amendments must be implemented into each agency’s implementing regulations, and each of those individual rulemakings could be subject to legal challenge. Additionally, in June 2023, President Biden signed the Fiscal Responsibility Act of 2023, which includes important changes to NEPA to streamline the environmental review process. The impact of changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our operations and our ability to obtain governmental permits.

Endangered Species Act and Migratory Bird Treaty Act

The ESA restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"). We may conduct operations on natural gas leases in areas where certain species that are or could be listed as threatened or endangered are known to exist. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for natural gas development. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. In October 2021, the Biden administration published two rules that reversed those changes, and in June and July 2022, the FWS issued final rules rescinding Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. In June 2023, the U.S. Fish and Wildlife Service issued three proposed rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. The comment periods for these rules ended in August 2023, and final rules are expected by April 2024. The designation of previously unprotected species as threatened or endangered or new critical or suitable habitat designations in areas where we conduct operations could result in limitations or prohibitions on our operations and could adversely impact our business, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. It is possible the October 2021 rules could increase the portion of our lease areas that could be designated as critical habitat. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

The Department of the Interior also issued an opinion in December 2017 that would narrow certain protections afforded to migratory birds pursuant to the MBTA. The MBTA makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit, and concurrently finalized a rule limiting application of the MBTA. The Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment to the Department of the Interior's plan to develop regulations that authorize incidental take under certain prescribed conditions. In October 2021, the FWS issued an advanced notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental take pursuant to the MBTA under certain prescribed conditions. The notice of proposed rulemaking was initially expected in October 2023 with a final rule to follow by April 2024; however, the notice of proposed rulemaking has not yet been issued. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

Worker Health and Safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. For example, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we maintain, organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some contamination risks associated with our development activities, including a coverage policy for gradual pollution events. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Human Capital Resources

We aim to provide a safe, healthy, respectful, and fair workplace for all employees. We believe our employees' talent and wellbeing is foundational to delivering on our corporate strategy, and that intentional human capital management strategies enable us to attract, develop, retain and reward our dedicated employees.

As of December 31, 2023, Mach Resources had 444 total employees, 442 of which were full-time employees. From time to time, we utilize the services of independent contractors to perform various field and other services. Neither we nor Mach Resources are a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. In general, we believe that employee relations are satisfactory.

Employee Safety and Health

The health, safety, and well-being or our employees is a top priority. In addition to our commitment to complying with all applicable safety, health, and environmental laws and regulations, we are focused on minimizing the risk of workplace incidents and preparing for emergencies as a priority element of our culture. We work to reduce safety incidents in our business and actively seek opportunities to make safety culture and procedural improvements.

Item 1A. Risk Factors

Our business involves a high degree of risk. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Additionally, new risks may emerge at any time and we cannot predict those risks or estimate the extent to which they may affect financial performance.

If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment.

Risks Related to Cash Distributions

We may not have sufficient available cash to pay any quarterly distribution on our common units following the payment of expenses, funding of development costs and establishment of cash reserves.

We may not have sufficient available cash each quarter to pay distributions on our common units. Under the terms of our partnership agreement, the amount of cash available for distribution will be reduced by our operating expenses, cash interest, development costs and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development, optimization and exploitation of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of available cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend on, among other factors:

- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our oil, natural gas and NGL production;
- the amount and timing of settlements on our commodity derivative contracts;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner and its affiliates for general and administrative expenses;
- the restrictive covenants in the Term Loan Credit Agreement and the Revolving Credit Agreement (collectively, the "Credit Agreements") and other agreements governing indebtedness that limit our ability to pay dividends or distributions in respect of our equity; and

- the level of our interest expenses, which will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Our future business performance may be volatile, and our cash flows may be unstable. We do not have a minimum quarterly distribution. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our unitholders will vary significantly from quarter to quarter and may be zero.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.

Our revenues, operating results, cash available for distribution, liquidity and ability to grow depend primarily upon the prices we receive for the natural gas, oil and NGLs we sell. We require substantial expenditures to replace our natural gas, oil and NGL reserves, sustain production and fund our business plans, including our development and exploratory drilling efforts. Historically, the markets for natural gas, oil and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas, oil and NGL prices may result from relatively minor changes in the supply of or demand for natural gas, oil and NGLs, market uncertainty and other factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- actions of the Organization of the Petroleum Exporting Countries and its allies (“OPEC+”), including the ability and willingness of the members of OPEC+ and other exporting nations to agree to and maintain oil price and production controls;
- changes in seasonal temperatures, including the number of heating degree days during winter months and cooling degree days during summer months;
- the level of oil, natural gas and NGL exploration, development and production;
- the level of oil, natural gas and NGL inventories;
- the level of U.S. LNG exports;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events
- prevailing prices on local price indexes in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and processing facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- the spot price of LNG on world markets;
- changes in ocean freight capacity, which could adversely impact LNG shipping capacity or lead to material interruptions in service or stoppages in LNG transportation;

- political and economic conditions in or affecting major LNG consumption regions or countries, particularly Asia and Europe;
- weather conditions and natural disasters, including those influenced by climate change;
- technological advances affecting energy consumption;
- the impact of energy conservation efforts;
- the price and availability of alternative fuels;
- activities that to restrict the exploration, development and production of oil and natural gas to minimize greenhouse gas (“GHG”) emissions;
- speculative trading in oil and natural gas derivative contracts;
- increased end-user conservation;
- U.S. trade policies and their effect on U.S. oil and natural gas exports;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes, including legislation or regulations addressing GHG emissions or requiring the reporting of GHG emissions or climate-related information.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements accurately. Lower commodity prices may reduce our operating margins, cash flow and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves or make acquisitions could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved and reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current WTI and Henry Hub strip prices may adversely affect our drilling economics, cash flow and our ability to raise capital, which may require us to re-evaluate and postpone or substantially restrict our development program, and result in the reduction of some of our proved undeveloped reserves and related PV-10. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, cash available for distribution, liquidity and ability to meet our financial commitments or cause us to delay our planned capital expenditures.

Currently, our producing properties are concentrated in the Anadarko Basin, making us vulnerable to risks associated with operating in a limited number of geographic areas.

As a result of our geographic concentration, adverse industry developments in our operating area could have a greater impact on our financial condition and results of operations than if we were more geographically diverse. We may also be disproportionately exposed to the impact of regional supply and demand factors, governmental regulations or midstream capacity constraints. Delays or interruptions caused by such adverse developments could have a material adverse effect on our financial condition and results of operations.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has recently been the case in our operating areas, we are subject to increasing competition for drilling rigs, workover rigs, tubulars and other well equipment, services, supplies as well as increased labor costs and a decrease in qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months or even longer, and, in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our development, production and acquisition activities, which are subject to numerous risks beyond our control. For example, we cannot assure you that wells we drill will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil, natural gas and NGLs often involves unprofitable efforts from wells that do not produce sufficient oil, natural gas and NGLs to return a profit at then-realized prices after deducting drilling, operating and other costs. In addition, our cost of drilling, completing and operating wells is often uncertain.

Our decisions to develop or purchase prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "— Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves."

Further, many factors may increase the cost of, curtail, delay or cancel our scheduled drilling projects, including:

- declines in oil, natural gas and NGL prices;
- increases in the cost of, and shortages or delays in the availability of, proppant, acid, equipment, services and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- capacity or pressure limitations on gathering systems, processing and treating facilities or other related midstream infrastructure;
- any future lack of available capacity on interconnecting transmission pipelines;
- delays imposed by, or resulting from, compliance with regulatory requirements, including limitations on freshwater sourcing, wastewater disposal, emissions of GHGs and hydraulic fracturing;
- pressure or irregularities in geological formations;
- limited availability of financing on acceptable terms;
- issues related to compliance with or liability arising under environmental laws and regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the air, surface and subsurface environment;
- compliance with contractual requirements;
- competition for surface locations from other operators that may own rights to drill at certain depths across portions of our leasehold;
- lack of available gathering facilities or delays in construction of gathering facilities;
- adverse weather conditions, such as hurricanes, lightning storms, flooding, tornadoes, snow or ice storms and changes in weather patterns;
- the availability and timely issuance of required governmental permits and licenses;
- title issues or legal disputes regarding leasehold rights; and
- other market limitations in our industry.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled certain drilling locations as an internal estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, availability and cost of sand and other proppant used in hydraulic fracturing operations and acid used for acid stimulation, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution and disposal systems, access to and availability of saltwater disposal systems, regulatory approvals, the cooperation of other working interest owners and other factors. Because of these uncertain factors, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil and natural gas from these or any other drilling locations. As such, our actual drilling activities may materially differ from those presently identified.

As a result of the limitations described in this Annual Report, we may be unable to drill many of our identified locations. In addition, although we plan to fund our drilling program entirely with cash flow from operations, if our cash flows are less than we expect or we alter our drilling plans, we may be required to borrow more under the Revolving Credit Agreement than we expect or issue new debt or equity securities in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "— Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves." Any drilling activities we are able to conduct on these locations may not be successful, may not result in production or additions to our estimated proved reserves and could result in a downward revision of our estimated proved reserves, which in turn could have a material adverse effect on the borrowing base under the Revolving Credit Agreement or our future business and results of operations. Additionally, if we curtail or cancel our drilling program, we may be required to reduce our estimated proved reserves, which could in turn reduce the borrowing base under the Revolving Credit Agreement.

Properties that we decide to drill may not yield oil and natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of geologic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess recoverable reserves, future oil and natural gas prices and their applicable differentials, development and operating costs, and potential liabilities, including environmental liabilities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices, but such a review may not reveal all existing or potential problems. Such assessments are inexact and inherently uncertain. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as any groundwater contamination or pipe corrosion, when a review is performed. We also may be unable to obtain contractual indemnities from the seller for liabilities arising 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. For these reasons, the properties we have acquired or will acquire in the future may not produce as expected or may not increase our cash available for distribution.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

As of December 31, 2023, approximately 22% of our total estimated proved reserves were classified as PUDs using SEC Pricing. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Estimated future development costs relating to the development of our PUDs on December 31, 2023 were approximately $815.5 million over the next five years. Our ability to fund these expenditures is subject to a number of risks. See "— Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves." Delays in the development of our PUDs, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the PV-10 value of our estimated PUDs and future net cash flows estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify some of our PUDs as unproved reserves. Furthermore, there is no certainty that we will be able to convert our undeveloped reserves to developed reserves or that our PUDs will be economically viable or technically feasible to produce.

Further, SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. As a result, we may be required to reclassify certain of our PUDs if we do not drill those wells within the required five-year timeframe.

Part of our business strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Difficulties that we face while completing our wells include:

- the ability to fracture stimulate the planned number of stages with the planned amount of proppant;
- the ability to source acid for our acid stimulation completion techniques;
- the ability to run tools through the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. If our development and production results are less than anticipated, the return on our investment for a particular well or region may not be as attractive as we anticipated, and we could incur material write-downs of our undeveloped acreage and its value could decline in the future.

The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of gathering, treating, processing and transportation pipelines, plants and other midstream facilities, a significant portion of which is owned by third parties. Some of our oil and natural gas production is collected from the wellhead by third-party gathering lines and transported to a gas processing or treating facility or transmission pipeline. We do not control these third-party facilities and our access to them may be limited, curtailed or denied. Pipelines, plants, and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements, and curtailments of receipts or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. The third-party facilities may experience unplanned downtime or maintenance for a variety of reasons outside our control and our production could be materially negatively impacted as a result of such outages. Insufficient production from our wells in the properties we do not operate to support the construction of pipeline facilities by third parties or a significant disruption in the availability of our or third-party midstream facilities or other production facilities could adversely impact our ability to deliver to market or produce our natural gas and thereby causing a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement gathering, treating, processing or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenues and cash flows and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the oil, natural gas and produced water that we gather and/or process, our revenues, cash flows and ability to make cash distributions to our unitholders could be materially adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary materially from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates of proved reserves to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant change could materially affect the estimated quantities and present value of our reserves. Furthermore, our development plan calls for completing horizontal wells using tighter well spacing and acid stimulation, which may increase the risk that these wells interfere with production from existing or future wells in the same spacing section and horizon, which in turn may result in lower recoverable reserves. There can be no assurance that our reserves will ultimately be produced or that our proved undeveloped reserves will be developed within the periods anticipated.

You should not assume that the present values of future net cash flows from our reserves presented in this Annual Report are the current market value of our estimated reserves. Actual future prices and costs may differ materially from those used in our present value estimates using SEC Pricing. If spot prices or future actual prices are below the prices used in our current reserve estimates, using those prices in estimating proved reserves may result in a decrease in proved reserve volumes due to economic limits. You should not assume that the standardized measure of proved reserves and PV-10 values of our estimated reserves are accurate estimates of the current fair value of our estimated oil, natural gas and NGL reserves.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, may not represent the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. For example, our estimated proved reserves as of December 31, 2023 were calculated under SEC rules using the unweighted arithmetic average first day of the month prices for the prior 12 months of $2.637/MMBtu for natural gas and $78.22/Bbl for oil at December 31, 2023, which, for certain periods during this period, were substantially different from the available spot prices. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with Accounting Standards Codification 932, “Extractive Activities — Oil and Gas,” may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Unless we replace our produced reserves with acquired or developed new reserves, our reserves and production will decline, which would adversely affect our future cash flows, results of operations and cash available for distribution.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas, secure trained personnel and raise additional capital.

Our ability to acquire additional oil and natural gas properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Many of our competitors possess and employ greater financial, technical and personnel resources than we do. Those companies may be able to pay more for oil and natural gas properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Those larger companies may also have a greater ability to continue development activities during periods of low oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring natural gas properties, developing reserves, marketing our production, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Our midstream services contracts are generally structured as short-term and long-term, fixed-fee contracts, which may negatively impact our operating margins and cash flow during periods of lower oil and natural gas prices.

We have entered into short-term and long-term, fixed-fee contracts with third parties for gathering, processing and transportation services, including four firm transportation contracts, three of which are fully utilized and one that is partially utilized, with the remainder released to other shippers or unutilized. The impact of the unutilized portion of this contract is assumed under the weighted average sales price in the reserves. Total remaining payments as of December 31, 2023 under firm transportation contracts were $7.0 million. In addition, under these short-term and long-term, fixed-fee arrangements, our gathering and processing expenses are generally fixed on a per unit basis for the term of the applicable contract and do not automatically adjust in response to a decline in oil and natural gas prices. In the event of a prolonged period of lower commodity prices, our revenue will decline while the per unit fees we pay for natural gas gathering, treating and compression services generally will not, which would negatively impact our operating margins and cash flow. In addition, during periods of depressed oil and natural gas prices, the market prices for such services may be lower than what we are contractually obligated to pay to our current third-party midstream service providers. Furthermore, to the extent certain future taxes or assessments are imposed on certain midstream assets we utilize, under certain circumstances we may be required by our midstream services contracts to reimburse the midstream service provider for such taxes or assessments, which could negatively affect our operating margins and cash flow. Our third-party midstream service providers are under no obligation to renegotiate their contracts with us. Our failure to obtain these services on competitive terms could materially harm our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We depend on Mach Resources to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.

We do not directly employ directors, officers or employees. Pursuant to the new management services agreement entered into with Mach Resources on October 27, 2023 in connection with the closing of the Offering (the "MSA"), an entity that is wholly owned by Tom L. Ward and his family, all of our executive management personnel are employees of Mach Resources, and we use a significant number of Mach Resources' employees to operate our properties and provide us with general and administrative services. If Mach Resources were to become unable or unwilling to provide such services, we would need to develop these services internally or arrange for the services from another service provider. Developing the capabilities internally or by retaining another service provider could have an adverse effect on our business, and the services, when developed or retained, may not be of the same quality as provided to us by Mach Resources. Additionally, if the MSA were to terminate, we would lose our key personnel.

Certain factors could require us to write down the carrying values of our properties, including commodity prices decreasing to a level such that our future undiscounted cash flows from our properties are less than their carrying value.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, drilling and completion results, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash impairment charge to earnings. Lower commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. We could experience further material write-downs as a result of other factors, including low production results or high lease operating expenses, capital expenditures or transportation fees.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We own non-operating interests in properties developed and operated by third parties and some of our leasehold acreage could be pooled by a third-party operator. As a result, we are unable, or may become unable as a result of pooling, to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other contractual arrangements. Similarly, our acreage in Oklahoma and Texas may be pooled by third-party operators under state law. If our acreage is involuntarily pooled under state forced pooling statutes, it would reduce our control over such acreage and we could lose operatorship over a portion of our acreage that we plan to develop.

We may not be able to maximize the value associated with acreage that we own but do not operate in the manner we believe appropriate, or at all. We cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator’s determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator’s operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator’s failure to adequately perform operations, breach of applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our business, financial condition and results of operations.

We may be unable to make accretive acquisitions or may make opportunistic dispositions. Any such acquisitions, if not integrated or conducted successfully, or such dispositions, if not conducted successfully, may disrupt our business and hinder our growth potential.

We may be unable to make accretive acquisitions or may make opportunistic dispositions. Any such acquisitions, if not integrated or conducted successfully, or such dispositions, if not conducted successfully, may disrupt our business and hinder our growth potential. Our ability to grow and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in cash available for distribution. In the future we may make acquisitions of assets or businesses that complement or expand our current business. There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions. In addition, from time to time, we may consider opportunistic dispositions, including dispositions of non-operating properties, having the potential to further limit future production.

The success of completed acquisitions will depend on our ability to effectively integrate the acquired businesses into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, the Credit Agreements impose certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness, which could limit our ability to acquire assets and businesses.

Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

The oil and gas industry is capital-intensive. A number of factors could cause our cash flow to be less than we expect, including the results of our drilling and completion program. Moreover, our capital budgets are based on a number of assumptions, including expected elections by working interest partners, drilling and completion costs, midstream service costs, oil and natural gas prices, and drilling results, and are therefore subject to change. If our cash flows are less than we expect, we decide to pursue acquisitions, or we change our capital budgets, we may be required to borrow more under credit facility than we expect or issue debt or equity securities to consummate such acquisitions or fund our drilling and completion program. The incurrence of additional indebtedness, either through borrowings under the Revolving Credit Agreement, the issuance of additional debt securities or otherwise, would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund capital expenditures, our development plan, acquisitions and cash distributions to unitholders. Additionally, the market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures with the issuance of additional equity. The issuance of additional equity securities may be dilutive to our unitholders The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things: oil and natural gas prices; actual drilling results; the availability and cost of drilling rigs and labor and other services and equipment; the availability, cost and adequacy of midstream gathering, processing, compression and transportation infrastructure; and regulatory, technological and competitive developments.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- the amount of our proved reserves;
- the amount of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the amount of our operating expenses;
- cash settlements from our derivative activities;
- our ability to borrow under the Revolving Credit Agreement; and
- our ability to access the debt and equity capital markets or sell non-core assets.

If our revenues or the borrowing bases under the Revolving Credit Agreement decrease as a result of lower commodity prices, operational difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to make acquisitions or sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under the Revolving Credit Agreement are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of the development of our properties, which in turn could lead to a decline in our reserves and production and could materially and adversely affect our business, financial condition and results of operations.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. For example, since March 2022, the Federal Reserve has raised its target range for the federal funds rate multiple times, and additional rate hikes may continue to occur. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices and drilling activity in our areas of operation and other major shale basins throughout the United States. These cost increases result from a variety of factors beyond our control, such as increases in the cost of sand and other proppant used in hydraulic fracturing operations or acid used for acid stimulation, and steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities. Furthermore, high oil prices have historically led to more development activity in oil-focused shale basins and resulted in service cost inflation across all U.S. shale basins, including our areas of operation. Higher levels of development activity in oil-focused shale basins have also historically resulted in higher levels of associated gas production that places downward pressure on natural gas prices. To the extent natural gas prices decline due to a period of increased associated gas production and we experience service cost inflation during such period, our cash flow, profitability and ability to make distributions to our unitholders may be materially adversely impacted.

The unavailability or high cost of drilling rigs, frac crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, frac crews, pipe and other equipment and supplies, including sand and other proppant used in hydraulic fracturing operations and acid used for acid stimulation, as well as for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with commodity prices or drilling activity in our areas of operation and in other shale basins in the United States, causing periodic shortages of supplies and needed personnel and rapid increases in costs. Increased drilling activity could materially increase the demand for and prices of these goods and services, and we could encounter rising costs and delays in or an inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to conduct our drilling and development activities, which could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs could have a material adverse effect on our cash flow and profitability.

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

For the year ended December 31, 2023, three purchasers each accounted for more than 10% of our revenue: Phillips 66 Company (52.6%), NextEra Energy Marketing, LLC (12.9%), and ONEOK Hydrocarbon L.P. (10.4%). We do not have long-term contracts with our customers; rather, we sell the substantial majority of our production contracts with terms of 12 months or less, including on a month-to-month basis, to a relatively small number of customers. The loss of any one of these purchasers, the inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have ready access to suitable markets for our future production. See “Business and Properties — Marketing and Customers” included in Items 1 and 2 of Part I of this Annual Report.

The availability of a ready market for any hydrocarbons we produce depends on numerous factors beyond our control, including, but not limited to, the extent of domestic production and imports of oil, the proximity and capacity of oil, natural gas and NGL pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil, natural gas and NGL production and federal regulation of oil, natural gas and NGLs sold in interstate commerce.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2023, we had $825.0 million outstanding under our Credit Agreements. In the future, we and our subsidiaries may incur substantial additional indebtedness. The Credit Agreements contain restrictions on the incurrence of additional indebtedness, and these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial. Additionally, the Credit Agreements permit us to incur certain amounts of additional indebtedness.

Our level of indebtedness could affect our operations in several ways, including the following:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our debt, thereby reducing the cash available to finance our operating and investing activities;

- limiting management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increasing our vulnerability to downturns and adverse developments in our business and industry;
- limiting our ability to raise capital on favorable terms;
- limiting our ability to raise available financing, make investments, lease equipment, sell assets and engage in business combinations;
- making us vulnerable to increases in interest rates;
- putting us at a competitive disadvantage relative to our competitors; and
- limiting our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities, due to covenants contained in our Credit Agreements, including financial covenants.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

The Credit Agreements contain a number of significant covenants, including restrictive covenants that, subject to certain qualifications, limit our ability to, among other things:

- make certain payments, including paying dividends or distributions in respect of our equity;
- incur additional indebtedness;
- make loans to others;
- make certain acquisitions and investments;
- make or pay distributions on our common units, if an event of default or borrowing base deficiency exists;
- merge or consolidate with another entity;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, the Credit Agreements require us to maintain compliance with certain financial covenants.

The restrictions in the Credit Agreements also impact our ability to obtain capital to withstand a downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our debt arrangements may impose on us.

A breach of any covenant in the Credit Agreements will result in a default under our Credit Agreements and an event of default if there is no grace period or if such default is not cured during any applicable grace period. An event of default, if not waived, could result in acceleration of the indebtedness outstanding under the applicable agreement and in an event of default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements to which we are a party. Any such accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Any significant reduction in our borrowing base under the Revolving Credit Agreement as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

The Revolving Credit Agreement limits the amounts we can borrow up to certain borrowing base amounts, which the administrative agent in good faith and in accordance with its usual and customary procedures for evaluating oil and gas loans and related assets at that particular time and otherwise acting in its sole discretion, will determine and which will be approved by the required lenders or all lenders, as applicable in the case of an increase in the borrowing base, on a semi-annual basis based upon projected revenues from our natural gas properties, our commodity derivative contracts securing our loan and certain other information (including, without limitation, the status of title information with respect to the oil and natural gas properties and the existence of any other indebtedness, liabilities, fixed charges, cash flow, business, properties, prospects, management and ownership, hedged and unhedged exposure to price, price and production scenarios, interest rate and operating cost changes). In addition to the scheduled redeterminations, the Company and the required lenders may request unscheduled interim redeterminations of the borrowing base not more than once between scheduled redeterminations. Any increase in the borrowing base will require the consent of all lenders (other than defaulting lenders). If the requisite number of required lenders or all lenders, as applicable in the case of an increase in the borrowing base, do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. The borrowing base may also automatically decrease upon the occurrence of certain events.

In the future, we may not be able to access adequate funding under the Revolving Credit Agreement as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a borrowing base redetermination, or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover a defaulting lender's portion. Furthermore, our borrowing base may be reduced if we sell assets in the future. Declines in commodity prices could result in a determination to lower the borrowing base and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions, make distributions to our unitholders or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

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

Borrowings under the Credit Agreements bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our business, financial condition and results of operations and cash available for distribution remain unchanged.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies and deposit accounts held at regional banks. In addition, if any lender under the Revolving Credit Agreement is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under the credit agreement.

Some of the Company's deposit accounts are held at regional banks. The recent high-profile bank failures involving Silicon Valley Bank, Signature Bank, and First Republic Bank have generated significant market volatility and, in particular, for regional banks. While the Department of the Treasury, the Federal Reserve, and the FDIC have made statements ensuring that depositors of recently failed banks would have access to their deposits, including uninsured deposit accounts, there is no guarantee that such actions will continue for future failed banks, including the regional banks that hold our deposit accounts.

Our ability to obtain financing on terms acceptable to us may be limited in the future by, among other things, increases in interest rates.

We require continued access to capital and our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. We may use the Revolving Credit Agreement to finance a portion of our future growth, and these factors could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Volatility in the global financial markets, significant losses in financial institutions' U.S. energy loan portfolios, or environmental and social concerns may lead to a contraction in credit availability impacting our ability to finance our operations or our ability to refinance the Credit Agreements or other outstanding indebtedness. An increase in interest rates could increase our interest expense and materially adversely affect our financial condition. A significant reduction in cash flow from operations or the availability of credit could materially and adversely affect our ability to carry out our development plan, our cash available for distribution and operating results.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into derivative contracts for a portion of our projected oil and natural gas production, primarily consisting of swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure About Market Risk — Commodity price risk — Commodity derivative activities." Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for the sale of our production; or
- there are issues regarding legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures, make payments on our indebtedness and make distributions to our unitholders, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties and oil and natural gas prices.

The cost to drill and complete oil and natural gas wells often increases in times of rising oil and natural gas prices. To the extent our drilling and completion costs increase, but our derivative arrangements limit the benefit we receive from increases in oil and natural gas prices, our margins could be limited, which could have a material adverse effect on our financial condition. In addition, the amount we pay in severance taxes is calculated without taking our derivative arrangements into account, and if our derivative arrangements limit the benefit we receive from increases in oil and natural gas prices, the effective tax rate we pay in severance taxes could increase.

Our derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices our derivative contract receivable positions would generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our derivative contracts.

The failure of our hedge counterparties, significant customers or working interest holders to meet their obligations to us may adversely affect our financial results.

Our hedging transactions expose us to the risk that a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make such party unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Any default by a counterparty to these derivative contracts when they become due could have a material adverse effect on our financial condition and results of operations.

Our ability to collect payments from the sale of oil and natural gas to our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fail to pay us for any reason, we could experience a material loss. In addition, if any of our significant customers cease to purchase our oil and natural gas or reduce the volume of the oil and natural gas that they purchase from us, the loss or reduction could have a detrimental effect on our revenues and may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

We also face credit risk through joint interest receivables. Joint interest receivables arise from billing entities who own partial working interests in the wells we operate. Though we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings, the inability or failure of working interest holders to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases, or the threat thereof, and any related threats of recession and other economic repercussions could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Widespread public health crises, epidemics, and outbreaks of infectious diseases, which can give rise to a threat of recession and related economic repercussions can create significant volatility, uncertainty and turmoil in the global economy and oil and gas industry, as did COVID-19 during 2020 through the beginning of 2022. These variables are beyond our control and may have the effect of disrupting the normal operations of many businesses, including the temporary closure or scale-back of business operations and/or the imposition of either quarantine or remote work or meeting requirements for employees, either by government order or on a voluntary basis. While the effects of the COVID-19 outbreak have lessened, widespread public health crises, epidemics and outbreaks of infectious diseases spreading throughout the U.S. and globally, including from a renewed outbreak of COVID-19, could result in significant disruptions to our operations. The global economy, our markets and our business have been, and may continue to be, materially and adversely affected by widespread public health crises, epidemics and outbreaks of infectious diseases, which could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, supply chain disruptions, increased demand, labor shortages associated with a fully employed U.S. labor force, geopolitical issues, inflation, the availability and cost of credit and the United States financial market and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which continued into 2023, due to a substantial increase in money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 7.5% in January 2022 to a peak of 9.1% in June 2022 and then decreased to 6.5% in December 2022. In December 2023, inflation was 3.4%. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures and protect the requisite access to commodities and services.

Nevertheless, we expect for the foreseeable future to experience supply chain constraints and inflationary pressure on our cost structure. We also may face shortages of these commodities and labor, which may prevent us from fully executing our development plan. These supply chain constraints and inflationary pressures will likely continue to adversely impact our operating costs and, if we are unable to manage our supply chain, it may impact our ability to procure materials and equipment in a timely and cost-effective manner, if at all, which could impact our ability to distribute available cash and result in reduced margins and production delays and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

We continue to take actions to mitigate supply chain and inflationary pressures. We are working closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical suppliers which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient.

In addition, continued hostilities related to the Russian invasion of Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors and other factors, such as another surge in COVID-19 cases or decreased demand from China, combined with volatile commodity prices, and declining business and consumer confidence may contribute to an economic slowdown and a recession. Recent growing concerns about global economic growth have had a significant adverse 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 ultimately adversely impact our business, financial condition and results of operations.

Oil and gas exploration and production companies are frequently subject to litigation claims from landowners, royalty owners and other interested parties, particularly during periods of declining commodity prices.

Title to oil and natural gas properties is often unclear and subject to claims by third parties. Additionally, oil and gas companies are frequently subject to claims with respect to underpayment of royalties, environmental hazards and contested ownership of properties, especially during periods of declining commodity prices and therefore revenue and royalty payments. The oil and gas exploration and production business is especially susceptible to increased cost of capital, hedging losses and declining revenues which can result in defaults on third party obligations. These risk and others can result in the incurrence of significant attorney's fees and other expenses incurred in the prosecution or defense of litigation.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We maintain insurance against some, but not all, operating risks and losses. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our operations are subject to all of the risks associated with drilling for and producing oil, natural gas and NGLs and operating gathering and processing facilities including the possibility of:

- environmental hazards, such as releases of pollutants into the environment, including groundwater, surface water, soil and air contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- ruptures, fires and explosions;
- damage to pipelines, processing plants, compression assets, water infrastructure, and related equipment and surrounding properties caused by tornadoes, floods, freezes, fires and other natural disasters;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these events could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims by government agencies or third parties for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties; and
- repair and remediation costs.

These events may also result in curtailment or suspension of our gathering and processing facilities. A natural disaster or any event such as those described above affecting the areas in which we and our third-party customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to us and our third-party customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on portions or all of our gathering facilities.

We may elect not to obtain insurance for certain of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, in some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, including for pollution and other environmental risks. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Extreme weather conditions and the physical risks of climate change could adversely affect our ability to conduct drilling activities in the areas where we operate and the operations of our gathering and processing facilities and have a negative impact on our business and results of operations.

The majority of the scientific community has concluded that climate change may result in more frequent and/or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. If any such effects were to occur, they could adversely affect or delay demand for oil or natural gas products or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. For example, our development, optimization and exploitation activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, thunderstorms, tornadoes and snow or ice storms, or other climate-related events such as wildfires and floods, in each case which may cause a loss of operational efficiency or production from temporary cessation of activity or lost or damaged facilities and equipment. Further, these types of interruptions could result in a decrease in the volumes supplied to our gathering systems, and delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering and processing facilities, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our third-party customers and thereby give rise to certain termination rights or other liabilities under our contracts. Such extreme weather conditions and events could also impact other areas of our operations, including the costs or availability of insurance, access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary resources, such as water, and third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations. Given that our operations are concentrated exclusively in the Anadarko Basin, a number of our properties could experience any of the same weather conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more geographically diversified portfolio of properties. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning.

Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and reduction in demand for oil and natural gas.

Increasing attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on combating climate change, together with changes in consumer and industrial/commercial behavior, societal pressure on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in the enactment of climate change-related regulations, policies and initiatives at the government, regulator, corporate and/or investor community levels, including alternative energy requirements, new fuel consumption standards, energy conservation and emissions reductions measures and responsible energy development; technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in wind, solar and hydrogen power, as well as battery technology); increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products. Such developments may also adversely impact, among other things, our stock price and access to capital markets, and the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Climate change-related developments may also impact the market prices of or our access to raw materials such as energy and water and therefore result in increased costs to our business.

More broadly, the enactment of climate change-related legislation and regulatory initiatives may in the future result in increases in our compliance costs and other operating costs. For further discussion regarding the risks posed to us by climate change-related legislation and regulatory initiatives, see "— Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business."

Negative perceptions regarding the Company's industry and related reputational risks may also in the future adversely affect the Company's ability to successfully carry out the Company's business strategy by adversely affecting the Company's access to capital. There have been efforts in recent years, for example, to influence the investment community, including investment advisors, insurance companies, and certain sovereign wealth, pension and endowment funds and other groups, by promoting divestment of fossil fuel equities and pressuring lenders to limit funding and insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Certain financial institutions and members of the investment community have shifted, and others may elect in the future to shift, some or all of their investment into non-fossil fuel related sectors. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies, such as the Company, have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Ultimately, this could make it more difficult to secure funding for exploration and production activities or adversely impact the cost of capital for both the Company and its customers, and could thereby adversely affect the demand and price of the Company's securities. Limitation of investments in and financings for energy companies could also result in the restriction, delay, or cancellation of infrastructure projects and energy production activities.

More broadly, negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change or other sustainability-related matters, may also lead to increased reputational and litigation risk and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new laws, regulations, guidelines and enforcement interpretations targeting our industry. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations, and such activism could materially and adversely impact our ability to operate our business and raise capital. The foregoing factors may result in downward pressure on the stock prices of oil and gas companies, including the Company's, and cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. For example, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas, or claims alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. Although the Company is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

Our operations are subject to stringent environmental laws and regulations that may affect our operations and expose us to significant costs and liabilities that could exceed current expectations.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, the release, disposal or discharge of materials into the environment, and occupational health and safety aspects of our operations. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated drilling activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; the prohibition of noise-producing activities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including threatened and endangered species habitats; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. We may be required to make significant capital and operating expenditures or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations (including plugging and abandonment obligations) and waste disposal practices. Spills or other releases of regulated substances, including such spills and releases that could occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. For example, lawsuits in which landowners sue every operator in the chain of title for environmental damages to their property are not uncommon in states in which we operate. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In certain instances, citizen groups also have the ability to bring legal proceedings against us regarding our compliance with environmental laws, or to challenge our ability to receive environmental permits that we need to operate. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations or historical oil and natural gas production in our areas of operation, which have been producing oil in certain instances for several decades. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

The long-term trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, particularly in light of the Biden administration's focus on addressing climate change, resulting in increased costs of doing business and consequently affecting profitability. For example, in January 2021, President Biden signed an executive order directing the U.S. Department of the Interior ("DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed subject to certain limitations, although litigation over the leasing pause remains ongoing. As a result, it is difficult to predict if and when such areas may be made available for future exploration activities. Further, in November 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule imposes emissions reduction standards on both new and existing sources in the oil and natural gas industry, expands the scope of Clean Air Act ("CAA") regulation by making regulations in Subpart OOOOa more stringent and creating a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA, and imposes emissions reductions targets to meet the stated goals of the U.S. federal administration. In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. In November 2022, the EPA issued the proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." In December 2023, the EPA announced a final rule, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane emissions from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply. Further, in September 2021, President Biden publicly announced the Global Methane Pledge, an international pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030, and in August 2022, President Biden signed the Inflation Reduction Act of 2022 into law, which incentivizes the reduction of methane emissions and would impose a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives. The Inflation Reduction Act amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program, which requires the EPA to impose a "waste emissions charge" on certain natural gas and oil sources that are already required to report under the EPA's Greenhouse Gas Reporting Program. To implement the program, the Inflation Reduction Act requires revisions to GHG reporting regulations for petroleum and natural gas systems (Subpart W) by 2024. In July 2023, the EPA proposed to expand the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities, as required by the Inflation Reduction Act. Among other things, the proposed rule would expand the emissions events that are subject to reporting requirements to include "other large release events" and apply reporting requirements to certain new sources and sectors. The rule is currently expected to be finalized in 2024 and become effective on January 1, 2025 in advance of the deadline for GHG reporting for 2024 (March 2025). In January 2024, the EPA proposed a rule implementing the Inflation Reduction Act's methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the Inflation Reduction Act. The methane emissions charge imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 in 2026. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry as well as our own results of operations, competitive position or financial condition.

To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and in the absence of comprehensive federal legislation on GHG emission control, the EPA has adopted regulations pursuant to the CAA to monitor, report, and/or reduce GHG emissions from various sources. We cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions, such as by means of cap and trade programs. Cap and trade programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. At the international level, in February 2021, pursuant to the Paris Agreement, the current administration announced reentry of the U.S. into the Paris Agreement (an international agreement from the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement for signatory countries to nationally determine their contributions and set GHG emission reduction goals) along with a new “nationally determined contribution” for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. In September 2021, President Biden publicly announced the Global Methane Pledge, an international pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030. To date, over 150 countries have joined the pledge. Further, at the 28th Conference of the Parties to the United Nations Framework Convention on Climate Change, member countries entered into an agreement that calls for actions toward achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts toward the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems. Various state and local governments have also vowed to continue to enact regulations to satisfy their proportionate obligations under the Paris Agreement.

Any legislation or regulatory programs addressing GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce, and could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements, and to monitor and report on GHG emissions. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Moreover, incentives or requirements to conserve energy, use alternative energy sources, reduce GHG emissions in product supply chains, and increase demand for low-carbon fuel or zero-emissions vehicles, could reduce demand for the oil and natural gas we produce. The Inflation Reduction Act of 2022, for example, provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture and other programs directed at addressing climate change. Additionally, the SEC adopted the SEC Climate Rules in March 2024, which will mandate detailed disclosure regarding material climate-related risks and related governance and risk management processes, among other items, for certain public companies. Further, in January 2024, President Biden announced a temporary pause on pending decisions on exports of LNG to non-free trade agreement countries until the Department of Energy can update the underlying analyses for authorizations, including an assessment of the impact of GHG emissions.

Although it is not currently possible to predict how these executive orders, national commitments or any proposed or future GHG or climate change legislation or regulation promulgated by Congress, the states or multi- state regions and their respective regulatory agencies will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business or on the assets we operate could result in increased compliance or operating costs or additional operating restrictions or reduced demand for our products, and could have a material adverse effect on our business, financial condition and results of operations. For further discussion of certain existing and proposed climate-related rules and regulations, see “Business and Properties — Legislative and regulatory environment” included in Items 1 and 2 of Part I of this Annual Report.

Increased scrutiny of ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

In recent years, companies across all industries are facing increasing scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors and lenders, investment funds and other influential investors and rating agencies, related to their ESG and sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Further, our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating company. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder confidence and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays, limit the areas in which we can operate, and reduce our oil and natural gas production, which could adversely affect our production and business.

Hydraulic fracturing is a common practice used to stimulate production of oil and/or natural gas from dense subsurface rock formations and is important to our business. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We and our third-party operators use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies or trigger seismic activity. Proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibiting the performance of well drilling in general or hydraulic fracturing in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

In addition, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act (“SDWA”) over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. The EPA also finalized rules under the Clean Water Act (“CWA”) in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. In March 2016, the U.S. Occupational Safety and Health Administration issued a final rule to impose stricter standards for worker exposure to silica, which went into effect in June 2018 and applies to use of sand as a proppant for hydraulic fracturing. The U.S. Department of the Interior’s Bureau of Land Management (“BLM”) finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. Following years of litigation, the BLM rescinded this rule in December 2017. However, California and various environmental groups filed lawsuits in January 2018 challenging the BLM’s rescission of the rule and, in March 2020, the U.S. District Court for the Northern District of California upheld the BLM’s decision to rescind the rule. However, there is ongoing litigation regarding the BLM rules, and future implementation of these rules is uncertain at this time. In November 2022, the BLM issued a proposed rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. Although the final rule was expected by January 2024, the final rule has not yet been issued.

New laws or regulations that impose new obligations on, or significantly restrict hydraulic fracturing, could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable and increase our cost of doing business. Such increased costs and any delays or curtailments in our production activities could have a material adverse effect on our business, prospects, financial condition, results of operations and liquidity.

Legislation or regulatory initiatives intended to address the disposal of saltwater gathered from our drilling activities could limit our ability to produce oil and natural gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of saltwater gathered from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

We are responsible for the decommissioning, abandonment, and reclamation costs for our facilities, which could decrease our cash available for distribution.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of our facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, abandonment and reclamation reserve funds to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease our cash available for distribution. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs and we will be responsible for the payment of the balance of such costs.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife and/or habitats. The Endangered Species Act (“ESA”) and (in some cases) comparable state laws were established to protect endangered and threatened species. The U.S. Fish and Wildlife Service (“FWS”) may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in material restrictions to land use and may materially delay or prohibit land access for natural gas development. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. In October 2021, the Biden administration published two rules that reversed those changes, and in June and July 2022, the FWS issued final rules rescinding Trump-era regulations concerning the definition of “habitat” and critical habitat exclusions. In June 2023, the U.S. Fish and Wildlife Service issued three proposed rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. The comment periods for these rules ended in August 2023, and final rules are expected by April 2024. The designation of previously unprotected species as threatened or endangered or new critical or suitable habitat designations in areas where we conduct operations could result in limitations or prohibitions on our operations and could adversely impact our business, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. Similar protections are offered to migratory birds under the MBTA, which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the United States. In October 2021, the FWS issued an advanced notice of proposed rulemaking seeking comment on the Department’s plan to develop regulations that authorize incidental take pursuant to the MBTA under certain prescribed conditions. The notice of proposed rulemaking was expected in October 2023 with a final rule to follow by April 2024; however, the notice of proposed rulemaking has not yet been issued. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered or further changes to regulations could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swap contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The full impact of the Dodd-Frank Act's swap regulatory provisions and the related rules of the CFTC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

In addition, the European Union and other non-U.S. jurisdictions have implemented and continue to implement regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, which could have adverse effects on our operations similar to the possible effects on our operations of the Dodd-Frank Act's swap regulatory provisions and the rules of the CFTC.

We may be involved in legal and regulatory proceedings that could result in substantial liabilities.

Like many oil and gas companies, we are, or may be, from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, alleged violations of federal or state securities laws and personal injury, environmental damage or property damage matters, in the ordinary course of our business. Additionally, members of our management and our directors may, from time to time, be involved in various legal and other proceedings against the Company naming those officers or directors as co-defendants. Such legal and regulatory proceedings are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition and affect the value of our common units. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material. The defense of any legal proceedings against us or our officers or directors, could take resources away from our operations and divert management attention. As of the date of this Annual Report, the Company is not aware of any material legal or environmental proceedings contemplated to be brought against the Company or its management.

Loss of our information and computer systems could adversely affect our business. Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, geologic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are subject to a number of privacy and data protection laws, rules and directives (collectively, data protection laws) relating to the processing of personal data.

The regulatory environment surrounding data protection laws is uncertain. Varying jurisdictional requirements could increase the costs and complexity of compliance with such laws, and violations of applicable data protection laws can result in significant penalties. A determination that there have been violations of applicable data protection laws could expose us to significant damage awards, fines and other penalties that could materially harm our business and reputation.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in 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 security and privacy breaches, which themselves may result in a violation of these laws. Additionally, the acquisition of a company that is not in compliance with applicable data protection laws may result in a violation of these laws.

Risks Inherent in an Investment in Us

Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. The Sponsor and Tom L. Ward through his ownership of Mach Resources own all of the membership interests in our general partner which are in the same proportion to each other as their limited partner interest ownership in us. The Sponsor and Tom L. Ward through his ownership of Mach Resources also own approximately 68,226,633 and 13,639,511, respectively, of our outstanding common units as of December 31, 2023. In addition, certain trusts affiliated with Mr. Ward for which an employee of Mach Resources is the trustee own approximately 1,599,133 of our outstanding common units. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of us and our unitholders, the executive officers and directors of our general partner also have a duty to manage our general partner at the direction of the Sponsor and Tom L. Ward through his ownership of Mach Resources. As a result of these relationships, conflicts of interest may arise in the future between the Sponsor, Tom L. Ward in his capacity as a member of our general partner through his ownership of Mach Resources and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand; provided, however, that under our code of business conduct, any such member of our management, so long as they are an executive officer, is required to avoid personal conflicts of interest and not compete against us, in each case unless approved by the Board. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of us and our common unitholders. These conflicts include, among others, the following:

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner’s liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- Neither our partnership agreement nor any other agreement requires the Sponsor (excluding our general partner) to pursue a business strategy that favors us;
- The Sponsor is not limited in its ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other partnerships with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 95% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report.

Our partnership agreement does not restrict the Sponsor from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Affiliates of our general partner are not prohibited from owning projects or engaging in businesses that compete directly or indirectly with us. Similarly, our partnership agreement does not limit the Sponsor's ability to compete with us and the Sponsor does not have any obligation to present business opportunities to us.

In addition, certain of our officers and directors may in the future hold similar positions with investment partnerships or other private entities that are in the business of identifying and acquiring mineral and royalty interests. In such capacities, these individuals would likely devote significant time to such other businesses and would be compensated by such other businesses for the services rendered to them. The positions of these directors and officers may give rise to duties that are in conflict with duties owed to us. In addition, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these potential future affiliations, they may have duties to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. The Sponsor will be under no obligation to make any acquisition opportunities available to us.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and holders of our common units.

Our partnership agreement replaces our general partner's fiduciary duties to us and our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with different contractual standards. For example, our partnership agreement provides that:

- whenever our general partner (acting in its capacity as our general partner), the Board or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was not adverse to our best interests, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or equitable principle;
- our general partner may make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners at the time our partnership agreement was entered into where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:
  - how to allocate corporate opportunities among us and its other affiliates;
  - whether to exercise its limited call right;
  - whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board; provided, however, the MSA will require our general partner to seek approval by the conflicts committee of the Board in connection with an amendment to the MSA that, in the reasonable discretion of our general partner, adversely affects our unitholders;
  - how to exercise its voting rights with respect to the units it owns;
  - whether to sell or otherwise dispose of any units or other partnership interests it owns; and
  - whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.
- our general partner will not have any liability to us or our unitholders for breach of any duty in connection with decisions made in its capacity as general partner so long as it acted in good faith (meaning that it subjectively believed that the decision was not adverse to our best interest);
- our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
  - approved by the conflicts committee of the Board, although our general partner is not obligated to seek such approval;
  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
  - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
  - determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we distribute each quarter all of our available cash, which we define as cash on hand at the end of each quarter, less reserves established by our general partner. As a result, we expect to rely primarily upon our cash reserves and external financing sources, including the issuance of additional common units and other partnership securities and borrowings under our Revolving Credit Agreement, to fund future acquisitions and finance our growth. To the extent we are unable to finance growth with our cash reserves and external sources of capital, the requirement in our partnership agreement to distribute all of our available cash may impair our ability to grow.

A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates, prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil, natural gas and NGLs.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are and will be no limitations in our partnership agreement or the Credit Agreements on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our business strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions to our unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt. See "— Increased costs of capital could adversely affect our business."

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain non-citizen unitholders.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the units held by any person (i) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain such proof. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business.

Our unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. The Board, including the independent directors, is chosen entirely by the Sponsor and Tom L. Ward through his ownership of Mach Resources, as a result of their ownership of our general partner, and not by our unitholders. Please read "Management of Mach Natural Resources" included in Item 10 of Part III of this Annual Report and "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner has control over all decisions related to our operations. Since affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) collectively own and control the voting of an aggregate of approximately 86.2% of our outstanding common units as of December 31, 2023, the other unitholders do not have an ability to influence any operating decisions and are not able to prevent us from entering into any transactions. However, our partnership agreement can generally be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources)). Assuming we do not issue any additional common units and affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) do not transfer any of their common units, affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) will generally have the ability to control any amendment to our partnership agreement, including our policy to distribute all of our cash available for distribution to our unitholders. Furthermore, the goals and objectives of the affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) that hold our common units relating to us may not be consistent with those of a majority of the other unitholders. Please read "— Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders."

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

The public unitholders are unable initially to remove our general partner without its consent because affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) own sufficient units to prevent the removal of our general partner. Our general partner may not be removed except by vote of the holders of at least 66⅔% of all outstanding units voting together as a single class is required to remove our general partner. As of December 31, 2023, affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) own approximately 86.2% of our outstanding common units, which enable those holders, collectively, to prevent the removal of our general partner.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the Sponsor or Tom L. Ward through his ownership of Mach Resources which controls our general partner, from transferring all or a portion of their ownership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board and officers of our general partner with their own choices and thereby influence the decisions made by the Board and officers.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;

- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common unitholders to influence the manner or direction of management.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

As of December 31, 2023, the Sponsor owns 68,226,633 common units, or approximately 71.8% of our limited partner interests, and management owns 16,773,367 common units, or approximately 17.7% of our limited partner interests. Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates, which includes the Sponsor and Tom L. Ward through his ownership of Mach Resources. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 95% of the then outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercises its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act of 1934, as amended (the "Exchange Act"). As of December 31, 2023, affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) own approximately 86.2% of our common units. Furthermore, certain trusts affiliated with Mr. Ward for which an employee of Mach Resources is the trustee own and control the voting of an aggregate of approximately 1.7% of our outstanding common units.

Our partnership agreement has designated the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders which would limit our unitholders' ability to choose the judicial forum for disputes with us or our general partner or its directors, officers or other employees.

Our partnership agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction) will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. The foregoing provision will not apply to any claims as to which the Court of Chancery determines that there is an indispensable party not subject to the jurisdiction of such court, which is rested in the exclusive jurisdiction of a court or forum other than such court (including claims arising under the Exchange Act), or for which such court does not have subject matter jurisdiction, or to any claims arising under the Securities Act and, unless we consent in writing to the selection of an alternative forum, the United States federal district courts will be the sole and exclusive forum for resolving any action asserting a claim arising under the Securities Act. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules or regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain such Securities Act claims. To prevent having to litigate claims in multiple jurisdictions and the threat of inconsistent or contrary rulings by different courts, among other considerations, the partnership agreement provides that, unless we consent in writing to the selection of an alternative forum, United States federal district courts shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. There is uncertainty as to whether a court would enforce the forum provision with respect to claims under the federal securities laws. If a court were to find these provisions of our amended and restated agreement of limited partnership inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding, including any claim under the U.S. federal securities laws, to the fullest extent permitted by applicable law. If a lawsuit is brought against us under our partnership agreement, it may be heard only by a judge or justice of the applicable trial court, which would be conducted according to different civil procedures and may result in different outcomes than a trial by jury would have, including results that could be less favorable to the plaintiffs in any such action. No unitholder can waive compliance with respect to the U.S. federal securities laws and the rules and regulations promulgated thereunder. If the partnership or one of the partnership unitholders opposed a jury trial demand based on the waiver, the applicable court would determine whether the waiver was enforceable based on the facts and circumstances of that case in accordance with applicable state and federal laws. To our knowledge, the enforceability of a contractual pre-dispute jury trial waiver in connection with claims arising under the U.S. federal securities laws has not been finally adjudicated by the United States Supreme Court. However, we believe that a contractual pre-dispute jury trial waiver provision is generally enforceable, including under the laws of the State of Delaware, which govern our partnership agreement. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations, provisions and obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us, our general partner and our general partner's directors and officers.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf pursuant to the MSA will reduce cash available for distribution to our unitholders. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. The amount and timing of such reimbursements will be determined by our general partner.

We and our general partner have entered into a MSA with Mach Resources pursuant to which Mach Resources will manage and perform all aspects of our oil and gas and midstream operations and other general and administrative functions in exchange for reimbursement of certain expenses. On a monthly basis, we will reimburse our general partner and its affiliates for certain expenses they incur and payments they make on our behalf pursuant to the MSA. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. The reimbursement of expenses to our general partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. For the year ended December 31, 2023, we paid $52.3 million to Mach Resources, which consisted of $4.8 million for a management fee and $47.5 million for reimbursements of its costs and expenses under the management services agreements among Mach Resources, the Company and the Mach Companies.

The NYSE does not require a publicly traded limited partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements. Please read "Management of Mach Natural Resources" included in Item 10 of Part III of this Annual Report.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a Delaware limited partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Our unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If our common unit price declines, our unitholders could lose a significant part of their investment.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;
- changes in securities analysts' recommendations and their estimates of our financial performance;
- public reaction to our press releases, announcements and filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- changes in tax law;
- an election by our general partner to convert or restructure us as a taxable entity;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure about our executive compensation. Taking advantage of the longer phase-in periods for the adoption of new or revised

financial accounting standards applicable to emerging growth companies may make our common units less attractive to investors.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for "emerging growth companies," including certain requirements relating to auditing standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, (2) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

We have elected to take advantage of all of the reduced reporting requirements and exemptions available to emerging growth companies under the JOBS Act, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act, until we are no longer an emerging growth company. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act.

Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the longer phase-in periods under Section 107 of the JOBS Act and who will comply with new or revised financial accounting standards. We cannot predict if investors will find our common units less attractive because we elected to rely on these exemptions. If some investors find our common units less attractive as a result, there may be a less active trading market for our common units and our common unit price may be more volatile. Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. As a newly public company, we are not required to make our first annual assessment of our internal controls over financial reporting pursuant to Section 404 until the year following our first annual report to be filed with the SEC, but we are required to disclose material changes made to our internal controls and procedures on a quarterly basis. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.

Under our partnership agreement, our general partner may, without unitholder approval, cause us to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal income tax purposes, whether by election of the partnership or conversion of the partnership or by any other means or methods. In addition and as part of such determination, affiliates of our general partner may choose to retain their partnership interests in us and cause us to enter into a transaction in which our interests held by other persons are converted into or exchanged for interests in a new entity, taxable as a corporation or subject to entity-level taxation for U.S. federal purposes, whose sole assets are interests in us. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may be material to such unitholder and may vary depending on the unitholder's particular situation and may vary from the tax liability of us or of any affiliates of our general partner who choose to retain their partnership interests in us. Our general partner will have no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of us or our limited partners.

We incur increased costs as a result of being a publicly traded partnership.

We have a limited history operating as a publicly traded partnership. As a publicly traded partnership, we incur significant legal, accounting and other expenses that we did not incur prior to our initial public offering. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. The amount of our expenses or reserves for expenses, including the costs of being a publicly traded partnership will reduce the amount of cash we have for distribution to our unitholders. As a result, the amount of cash we have available for distribution to our unitholders will be affected by the costs associated with being a public company.

We are subject to the public reporting requirements of the Exchange Act. These rules and regulations increase certain of our legal and financial compliance costs and make activities more time-consuming and costly. For example, as a result of becoming a publicly traded company, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting.

We also incur additional expense in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on the Board or as executive officers than it was prior to our initial public offering.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our units or if our operating results do not meet their expectations, our unit price could decline.

The trading market for our common units is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our unit price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common units or if our operating results do not meet their expectations, our unit price could decline.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (the "IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our classification as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders could be reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, capital, and other forms of business taxes, as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in Oklahoma, Kansas and Texas, among other states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships or an investment in our common units, including elimination of partnership tax treatment for certain publicly traded partnerships. For example, in recent years, the Biden administration has proposed repealing the exemption from the corporate income tax for "fossil fuel" publicly traded partnerships in its budget, which is published annually.

Any changes to U.S. federal income tax laws or interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for U.S. federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes to U.S. federal income tax laws or interpretations thereof could adversely impact the value of an investment in our common units.

Certain U.S. federal income tax incentives currently available with respect to oil and natural gas exploration and production may be reduced or eliminated as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted, make significant changes to U.S. tax laws, including the reduction or elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the U.S. federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS has made no determination as to our status as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. If we bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns (including any income tax returns filed by us or the Mach Companies in respect of periods beginning prior to the closing of our initial public offering), it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be made or be effective in all circumstances. If we are unable to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, our unitholders may be required to pay U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder's tax basis in those common units, even if the price received is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items such as depreciation, depletion, amortization and accretion expense and intangible drilling costs. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business ("business interest") may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investments in our common units by tax-exempt entities, such as individual retirement accounts ("IRAs") or other retirement plans, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. A tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor regarding the impact of these rules on an investment in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our common units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable marginal tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, upon the sale, exchange or other disposition of a common unit by a non-U.S. unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the "amount realized" on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Distributions to non-U.S. unitholders may also be subject to additional withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation, depletion, amortization and accretion positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in Oklahoma, Kansas and Texas. Oklahoma and Kansas each impose a personal income tax. Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or entity-level income tax. It is the responsibility of each unitholder to file its own U.S. federal, state and local tax returns, as applicable.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many of the relative fair market value estimates ourselves. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction. A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Mach's cybersecurity posture is proactive and multifaceted, reflecting our prioritization of protecting our organization against cyber threats. Through the implementation of advanced technologies and adherence to rigorous standards, we have established a layered defense strategy to protect our information and computer systems and align with industry best practices.

Risk Management and Strategy

Our approach to cybersecurity is comprehensive, and includes continuous risk management strategies to safeguard our digital assets and ensure the integrity and confidentiality of our data.

We employ a strategic combination of the National Institute of Standards and Technology (NIST) Cybersecurity Framework, the International Organization for Standardization (ISO), and the Center for Internet Security (CIS) best practice standards to benchmark and enhance our cybersecurity measures. This multifaceted approach allows us to maintain a robust security posture, manage risks, and respond to evolving cyber threats.

Our cybersecurity practices include:

Data Monitoring and Loss Prevention: We continuously scan and monitor our systems to detect and prevent data breaches, ensuring sensitive information remains secure.

- Network Vulnerability Testing: Regular assessments of our network's security through certified third-party testers to identify and remediate vulnerabilities.

- Robust Encryption: Implement strong encryption protocols to protect data in transit and at rest, mitigating the risk of unauthorized access.

- Continuous Monitoring: We are monitoring our digital environment continually to detect and respond to potential security incidents quickly.

- Regular Updates: Systematic updates to our security systems in response to new threats and vulnerabilities, ensuring our defenses remain effective.

Management

Cybersecurity is a paramount enterprise risk, demanding vigilant attention and strategic planning. Our Chief Information Officer, with over 20 years of technological and leadership experience in the oil and gas industry, oversees all aspects of information technology, including cybersecurity, networking, infrastructure, applications, data management and protection. The Cybersecurity Team led by the CIO, assesses and manages cybersecurity threats, oversees the comprehensive cybersecurity risk management program, and supervises both the internal IT staff and external cybersecurity consultants.

The Cybersecurity Team serves a crucial role in reporting significant incidents to the Chief Information Officer. The Cybersecurity Team, along with our Chief Information Officer, convenes at least once a week to review any incidents related to digital security and the corresponding response actions, analyze emerging threats to the organization's cybersecurity landscape, and deliberate on and discuss preventative strategies. Our internal cybersecurity team receives cybersecurity news and updates from various private energy sector and federal security working groups and organizations.

Governance

Cybersecurity risks are managed alongside the Company’s other enterprise risks, which the Board of Directors oversees. The Company's IT security efforts, encompassing cybersecurity, fall under the oversight of the Audit Committee within the Board of Directors. The Company's cybersecurity strategy undergoes a quarterly review by the Audit Committee. During these sessions, the Chief Information Officer (CIO) provides a comprehensive update to the committee on cybersecurity and data protection matters. This includes an assessment of the Company's actions to recognize and reduce cybersecurity risks. Furthermore, the Company adheres to established procedures for reporting significant cybersecurity events to the Audit Committee or the Board, as appropriate.

To date, the company has not experienced any material cybersecurity incidents, and we are not aware of any cybersecurity risks that are reasonably likely to materially affect our business strategy, results or financial condition. Please see “Risk Factors” in Item 1A in this Annual Report on Form 10-K for further discussion regarding the Company’s cybersecurity risks.

Item 3. Legal Proceedings

We may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business. We are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal proceedings contemplated to be brought against the Company. For more information on our legal contingencies see Note 10 in “Item 8. Financial Statements and Supplementary Data” of this Annual Report.

As an owner and operator of oil and natural gas properties, we are subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution cleanup resulting from operations and subject the lessee to liability for pollution damages. In some instances, we may be directed to suspend or cease operations in the affected area. We maintain insurance coverage that is customary in the industry, although we are not fully insured against all environmental risks.

We are not aware of any environmental claims existing as of December 31, 2023. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered on our oil and natural gas properties.

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

Our common units are listed and traded on the NYSE under the ticker symbol "MNR." As of March 15, 2024, there were 95,000,000 common units outstanding held by 8 holders of record. Because many of our common units are held by brokers and other institutions on behalf of unitholders, we are unable to estimate the total number of unitholders represented by these holders of record.

Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash each quarter. Our cash distribution policy reflects a basic judgment that our unitholders generally will be better served by us distributing our available cash, after costs, expenses and reserves, rather than retaining it. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions from our available cash in the aforementioned or any other amount, and our general partner has considerable discretion to determine the amount of cash available for distribution each quarter.

Because our policy will be to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions from our available cash, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by our general partner to:

• provide for the proper conduct of our business, which will include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

• comply with applicable law, any of our debt instruments or other agreements; or

• provide funds for distributions to our unitholders for any one or more of the next four quarters;

plus, all cash and cash equivalents on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;

plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Unregistered Sale of Equity Securities

On October 25, 2023, the Company underwent the Corporate Reorganization whereby (a) the Existing Owners who directly held membership interests in the Mach Companies contributed 100% of their membership interests in the Mach Companies for a pro rata allocation of 100% of the limited partner interests in the Company, (b) the Company contributed 100% of its membership interests in the Mach Companies to Intermediate in exchange for 100% of the membership interests in Intermediate, and (c) Intermediate contributed 100% of its membership interests in the Mach Companies to Holdco in exchange for 100% of the membership interests in Holdco.

The referenced issuances did not involve any underwriters, underwriting discounts or commissions, or any public offering and we believe such issuances are exempt from the registration requirements of the Securities Act by virtue of Section 4(a)(2) thereof and/or Regulation D promulgated thereunder.

Use of Proceeds

On October 24, 2023, the Registration Statement (File No. 333-274662) was declared effective by the SEC for the Offering pursuant to which the Company registered and sold an aggregate of 10,000,000 common units at a price of $19.00 per common unit to the public. The sale of the common units resulted in gross proceeds of $190.0 million to the Company and net proceeds of $168.5 million, after deducting underwriting fees and offering expenses.

The Company used $102.2 million of the proceeds to pay down the Pre-IPO Credit Facilities of its operating subsidiaries and $66.3 million of the proceeds to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 6. [Reserved]
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. The following discussion and analysis should be read in conjunction with the historical audited consolidated financial statements and related notes included in Item 8 of Part II of this Annual Report and also with "Risk Factors" included in Item 1A of Part I of this Annual Report. We have applied provisions of the SEC's FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent fiscal years. The following information updates the discussion of our financial condition provided in our previous filings, and analyzes the changes in the results of operations between the years ended December 31, 2023 and 2022. Refer to our final prospectus, filed with the SEC on October 26, 2023, pursuant to Rule 424(b)(4) of the Securities Act, for discussion and analysis of the changes in results of operations between the years ended December 31, 2022 and 2021.

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance, which may affect our future operating results and financial position. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Actual results and the timing of the events could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGLs, production volumes, estimates of proved reserves, capital expenditures, economic, inflationary and competitive conditions, drilling results, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly under "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

We are an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas, and we operate approximately 4,600 PDP wells.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Woodford, Meramec/Osage and Mississippi Lime formations. Our experience in the Anadarko Basin and these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments. We also own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue.

Market Outlook

Our financial results depend on many factors, particularly commodity prices and our ability to find, develop and market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand. The oil and natural gas industry is cyclical and commodity prices are highly volatile and we expect continued and increased pricing volatility in the crude oil and natural gas markets. Oil prices have been affected by increased demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. For example, during the period from December 31, 2020 through December 31, 2023, prices for crude oil and natural gas reached a high of $123.64 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.47 per Bbl and $1.74 per MMBtu, respectively. Starting in 2022, NYMEX oil and natural gas futures prices strengthened following the reduction of pandemic-related restrictions and increased OPEC+ cooperation. During the first quarter of 2023, the price of crude oil decreased as the global oil market saw higher inventory levels; however, prices remained above the 10-year average from 2010 through 2019. The increase in inventory levels was followed by an early June announcement from OPEC + oil producers to further reduce oil output. The Energy Information Administration ("EIA") forecasts global oil inventories to fall slightly in each of the next five quarters and projects these draws will put upward pressure on crude oil prices, notably in late-2023 and early-2024. Also during the first quarter of 2023, natural gas prices remained above the 10-year range, despite declining significantly in the quarter as milder weather eased demand for natural gas heating, allowing storage levels to increase above historical averages in the United States and Europe. The EIA projects that the U.S. benchmark Henry Hub natural gas spot price to rise in the summer months due to rising natural gas use in the electric power sector and flattening production growth, which together contribute to storage injections that are less than the five-year average from 2018 through 2022 in the coming months.

Further, although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which continued into 2023, due to a substantial increase in the money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 7.5% in January 2022 to a peak of 9.1% in June 2022 and then decreased to 6.5% in December 2022. In December 2023, inflation was 3.4%. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience cost increases in our operations, including costs for drill rigs, workover rigs, tubulars and other well equipment, as well as increased labor costs. We continue to evaluate actions to mitigate supply chain and inflationary pressures and work closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical supplies which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient. Further, if we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, borrowing base calculations, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions would all be significantly impacted.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including the following sources of our revenue, principal components of our cost structure and other financial metrics:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs;
- lease operating expense ("LOE");
- Adjusted EBITDA; and
- cash available for distribution.

Factors Affecting the Comparability of Our Future Results of Operations to Our Historical Results of Operations

Our future results of operations may not be comparable to our historical results of operations for the periods presented, primarily for the reasons described below.

Acquisitions

We have completed eleven acquisitions since 2021. These acquisitions are reflected in our results of operations as of and after the date of completion for each such acquisition. As a result, periods prior to each such acquisition will not contain the results of such acquired assets which will affect the comparability of our results of operations for certain historical periods. We may continue to grow our operations through acquisitions when economical, including by funding such acquisitions under our Revolving Credit Agreement.

On January 1, 2023, we assumed operations of a significant amount of properties where we previously were a non-operating partner in the properties and provided midstream services. As a result of these properties becoming operated properties as opposed to non-operated properties, offsetting accounting changes occurred resulting in reduced midstream operating expense, reduced midstream revenue, increased LOE, and increased price realizations.

Corporate Reorganization

The historical consolidated financial statements included in this Annual Report are of our Predecessor for periods prior to the Corporate Reorganization, and of the Company for periods after the Corporate Reorganization. Our historical financial data presented herein does not present what our actual performance results would have been on a combined basis for the full fiscal period presented.

Public Company Expenses

Upon the completion of our initial public offering, we incurred and expect to continue to incur incremental non-recurring costs related to our transition to a publicly traded partnership, including the costs of our initial public offering and the costs associated with the initial implementation of our internal control implementation and testing. We also expect to incur additional significant and recurring expenses as a publicly traded partnership, including costs associated with the employment of additional personnel, compliance under the Exchange Act, annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation.

Results of Operations

Year Ended December 31, 2023 Compared to the Year Ended December 31, 2022

Revenue

The following table provides the components of our revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

($ in thousands)	Year Ended December 31, 2023	Year Ended December 31, 2022	Change Amount	Change Percent
Revenues:				
Oil	$ 422,312	$ 448,567	$ (26,255)	(6 %)
Natural gas	149,795	301,423	(151,628)	(50 %)
Natural gas liquids	75,245	110,398	(35,153)	(32 %)
Total oil, natural gas, and NGL sales	647,352	860,388	(213,036)	(25 %)
Gain (loss) on oil and natural gas derivatives, net	57,272	(67,453)	124,725	(185 %)
Midstream revenue	26,328	44,373	(18,045)	(41 %)
Product sales	31,357	100,106	(68,749)	(69 %)
Total revenues	$ 762,309	$ 937,414	$ (175,105)	(19 %)
Average Sales Price[(1)]:				
Oil ($/Bbl)	$ 77.57	$ 93.43	$ (15.86)	(17 %)
Natural gas ($/Mcf)	$ 2.52	$ 6.34	$ (3.82)	(60 %)
NGL ($/Bbl)	$ 24.52	$ 39.27	$ (14.75)	(38 %)
Total ($/Boe) – before effects of realized derivatives	$ 35.16	$ 55.37	$ (20.21)	(36 %)
Total ($/Boe) – after effects of realized derivatives	$ 35.62	$ 49.53	$ (13.91)	(28 %)
Net Production Volumes:				
Oil (MBbl)	5,445	4,801	644	13 %
Natural gas (MMcf)	59,378	47,561	11,817	25 %
NGL (MBbl)	3,068	2,812	256	9 %
Total (MBoe)	18,409	15,539	2,870	18 %
Average daily total volumes (MBoe/d)	50.44	42.57	7.87	18 %

(1) Average sales prices reflected above exclude gathering and processing expense.

Revenue and Other Operating Income

Oil, natural gas and NGL sales

Revenues from oil, natural gas and NGL sales decreased $213.0 million, or 25%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. This decrease is primarily a result of a 17% decrease in the average selling price on oil resulting in a decrease in oil sales revenue of $76.2 million, a 60% decrease in the average selling price on natural gas resulting in a decrease in natural gas sales revenue of $181.4 million, and a 38% decrease on the average selling price on NGLs resulting in a decrease in NGL sales revenue of $41.5 million. An increase in production of 2,870 MBoe for the year ended December 31, 2023, as compared to the year ended December 31, 2022, resulted in an increase in oil, natural gas and NGL revenues of $86.0 million.

Oil, natural gas and NGL production

Production increased 2,870 MBoe, or 18%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The increase was primarily attributable to an increase in production of 1,239 MBoe as a result of additional production from acquisitions that closed in 2023, as well as production from wells drilled subsequent to December 31, 2022, offset by natural production declines in our existing producing wells.

Oil and natural gas derivatives

For the year ended December 31, 2023, we had realized gains on derivative instruments of $8.4 million and an unrealized gain of $48.9 million for total gains of $57.3 million. For the year ended December 31, 2022, we had realized losses on derivative instruments of $90.8 million and an unrealized gain of $23.3 million for total losses of $67.5 million. The increase in realized gains is primarily from the overall decrease in oil and gas prices in 2023.

Midstream revenue

Midstream revenue decreased $18.0 million, or 41%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022, primarily due to lower non-operated throughput in our midstream facilities. Of the total decrease, $10.2 million relates to decreases in fee revenue for gathering and processing, and $7.8 million is due to decreased saltwater gathering and disposal revenue.

Product sales

Product sales decreased $68.7 million, or 69%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. This decrease was primarily a result of decreases in non-operated production resulting in lower overall product sales, compounded by the decrease in the average selling price on natural gas and NGLs. These decreases corresponded with the decrease in our cost of product sales noted below.

Operating Expenses

The following table summarizes our expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	Year Ended December 31,		Change	
($ in thousands)	**2023**	**2022**	**Amount**	**Percent**
Operating Expenses:				
Gathering and processing expense	$ 39,449	$ 47,484	$ (8,035)	(17 %)
Lease operating expense	127,602	95,941	31,661	33 %
Production taxes	31,882	47,825	(15,943)	(33 %)
Midstream operating expense	10,873	15,157	(4,284)	(28 %)
Cost of product sales	28,089	94,580	(66,491)	(70 %)
Depreciation, depletion, amortization and accretion expense – oil and natural gas	131,145	84,070	47,075	56 %
Depreciation and amortization expense – other	6,472	4,519	1,953	43 %
General and administrative	27,653	25,454	2,199	9 %
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 2.14	$ 3.06	$ (0.92)	(30 %)
Lease operating expense	$ 6.93	$ 6.17	$ 0.76	12 %
Production taxes (% of oil, natural gas and NGL sales)	4.9 %	5.6 %	(0.7 %)	(13 %)
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 7.12	$ 5.41	$ 1.71	32 %
Depreciation and amortization expense – other	$ 0.35	$ 0.29	$ 0.06	21 %
General and administrative	$ 1.50	$ 1.64	$ (0.14)	(9) %

Gathering and processing expense

Gathering and processing expense decreased by $8.0 million, or 17%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022, primarily due to decreased natural gas prices leading to lower fuel costs. Gathering and processing expense per Boe produced decreased by $0.92 due to lower expense that fluctuated with the decrease in commodity gas prices.

Lease operating expense

Lease operating expense increased $31.7 million, or 33% and by $0.76 per Boe , for the year ended December 31, 2023, as compared to the year ended December 31, 2022. Lease operating expense increased primarily as a result of additional wells brought on-line as a result of the drilling activity subsequent to December 31, 2022. Additionally, we closed on four acquisitions throughout the year ended December 31, 2022, and four acquisitions in the year ended December 31, 2023, which all have unique cost and production profiles. Accordingly, 2023 includes a full year of lease operating expenses for acquisitions that closed in 2022, as well as new lease operating expense for acquisitions in 2023.

Production taxes

Production taxes decreased $15.9 million, or 33%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. This decrease was primarily a result of a decrease in the average selling price on all products, resulting in a decrease of $22.3 million in production taxes, offset by an increase in production, resulting in an increase of $6.4 million in production taxes. Production taxes as a percentage of revenue decreased from 5.6% for the year ended December 31, 2022 to 4.9% for the year ended December 31, 2023. The effective tax rate can have minor fluctuations due to the overall product mix and related tax deductions available for each product.

Midstream operating expense

Midstream operating expense decreased $4.3 million, or 28%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022, primarily due to a decrease in water disposal costs of $2.4 million and gathering operating expense of $1.3 million, both of which decreased as a result of us taking over as operator on a significant number of wells beginning January 1, 2023.

Cost of product sales

Cost of product sales decreased $66.5 million, or 70%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. This decrease was primarily a result of decreases in non-operated production resulting in lower overall cost of product sales, compounded by the decrease in the average selling price on natural gas and NGLs. These decreases were offset with the decrease in product sales noted above.

Depreciation, depletion, amortization and accretion expense

Depreciation, depletion, amortization and accretion expense for oil and natural gas properties increased by $47.1 million, or 56%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The increase is primarily attributable to additional drilling activities and acquisitions in both 2022 and 2023 that added to the depletable base and overall changes on reserve inputs used in the depletion calculation. Depreciation and amortization expense for other assets increased $2.0 million, or 43%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022, primarily due to acquisitions and additional assets acquired during the year.

General and administrative costs

General and administrative costs increased $2.2 million, or 9%, for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The increase in general and administrative costs was primarily due to an increase in compensation and benefits of $5.3 million driven by change of control bonus payments of $4.5 million recognized as a result of the initial public offering in 2023, offset by a decrease of $4.1 million in equity compensation expense recorded in the year ended December 31, 2023, as compared to the year ended December 31, 2022.

Non-GAAP Financial Measures

Adjusted EBITDA

We include in this Annual Report the supplemental non-GAAP financial performance measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income, our most directly comparable financial measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income before (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration and (6) (gain) loss on sale of assets.

Adjusted EBITDA is used as a supplemental financial performance measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to more effectively evaluate our operating performance and our results of operation from period to period and against our peers without regard to financing methods, capital structure or historical cost basis. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as indicators of our operating performance. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual items. Our computations of Adjusted EBITDA may not be identical to other similarly titled measures of other companies.

Cash Available for Distribution

Cash available for distribution is not a measure of net income or net cash flow provided by or used in operating activities as determined by GAAP. Cash available for distribution is a supplemental non-GAAP financial performance measure used by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess our ability to internally fund our exploration and development activities, pay distributions, and to service or incur additional debt. We define cash available for distribution as net income less (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration, (6) (gain) loss on sale of assets, (7) settlement of asset retirement obligations, (8) net cash interest expense, (9) development costs, (10) settlement of contingent consideration and (11) change in accrued realized derivative settlements. Development costs include all of our capital expenditures, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances. Cash available for distribution is not a measurement of our financial performance or liquidity under GAAP and should not be considered as an alternative to, or more meaningful than, net income or net cash provided by or used in operating activities as determined in accordance with GAAP or as indicators of our financial performance and liquidity. The GAAP measures most directly comparable to cash available for distribution are net income and net cash provided by operating activities. Cash available for distribution should not be considered as an alternative to, or more meaningful than, net income or net cash provided by operating activities.

Reconciliations of GAAP Financial Measures to Adjusted EBITDA and Cash Available for Distribution

The following table presents our reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measures Adjusted EBITDA and cash available for distribution, as applicable, for each of the periods indicated.

	Year Ended December 31,	
(in thousands)	**2023**	**2022**
Net Income Reconciliation to Adjusted EBITDA:		
Net income	$ 346,558	$ 516,841
Interest expense, net	9,546	4,852
Depreciation, depletion and amortization	137,617	88,589
Unrealized (gain) loss on derivative investments	(48,826)	(23,335)
Equity-based compensation expense	3,440	7,527
Credit losses	1,746	—
(Gain) loss on sale of assets	(1)	(45)
Adjusted EBITDA	$ 450,080	$ 594,429
Net Income Reconciliation to Cash Available for Distribution:		
Net income	$ 346,558	$ 516,841
Interest expense, net	9,546	4,852
Depreciation, depletion and amortization	137,617	88,589
Unrealized (gain) loss on derivative investments	(48,826)	(23,335)
Equity-based compensation expense	3,440	7,527
Credit losses	1,746	—
(Gain) loss on sale of assets	(1)	(45)
Settlement of asset retirement obligations	(537)	(49)
Cash interest expense, net	(7,596)	(4,477)
Development costs	(302,799)	(271,999)
Settlement of contingent consideration	—	(13,547)
Change in accrued realized derivative settlements	(4,029)	(3,413)
Cash Available for Distribution	$ 135,119	$ 300,944
Net Cash Provided by Operating Activities Reconciliation to Cash Available for Distribution:		
Net cash provided by operating activities	$ 491,742	$ 553,542
Change in operating assets and liabilities	(53,824)	19,401
Development costs	(302,799)	(271,999)
Cash Available for Distribution	$ 135,119	$ 300,944

Reconciliation of PV-10 to Standardized Measure

Certain of our oil and natural gas reserve disclosures included in this Annual Report are presented on a PV-10 basis. PV-10 is a non-GAAP financial measure and represents the estimated present value of the future cash flows less future development and production costs from our proved reserves before income taxes discounted using a 10% discount rate. PV-10 of proved reserves generally differs from the standardized measure of discounted future net cash flows from production of proved oil and natural gas reserves (the “Standardized Measure”), the most directly comparable GAAP financial measure, because it does not include the effects of future income taxes, as is required under GAAP in computing the Standardized Measure. However, our PV-10 for proved reserves using SEC pricing and the Standardized Measure of proved reserves are equivalent because we were not subject to entity level taxation. Accordingly, no provision for federal or state income taxes has been provided in the Standardized Measure because taxable income is passed through to our unitholders.

We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and natural gas companies. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of PV-10 value provides greater comparability when evaluating oil and natural gas companies. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. However, the definition of PV-10 value as defined above may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value as defined may not be comparable to similar measures provided by other companies.

Investors should be cautioned that neither PV-10 nor Standardized Measure of proved reserves represents an estimate of the fair market value of our proved reserves. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

Liquidity and Capital Resources

Our primary sources of liquidity and capital are cash flows generated by operating activities and borrowings under our Credit Agreements. Outstanding borrowings under our Credit Agreements were $825.0 million at December 31, 2023, and the remaining availability under our Credit Agreements was $70.0 million at December 31, 2023. After the close of the Offering in October 2023, we utilized the proceeds to pay down the Pre-IPO Credit Facilities of the Company's operating subsidiaries (the "Pre-IPO Credit Facilities") and to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis.

As a publicly traded partnership, our primary sources of liquidity and capital resources are from cash flow generated by operating activities, borrowings under the Credit Agreements, and proceeds from the issuance of equity and debt. Historically, our primary sources of liquidity have also included capital contributions by our equity holders, but we do not expect to rely on management or our partners for capital in the future. We may need to utilize the public equity or debt markets and bank financings to fund future acquisitions or capital expenditures, but the price at which our common units will trade could be diminished as a result of the limited voting rights of unitholders. We expect to be able to issue additional equity and debt securities from time to time as market conditions allow to facilitate future acquisitions. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations or to refinance our indebtedness will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory, weather and other factors.

Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner, which we refer to as "available cash." Our quarterly cash distributions may vary from quarter to quarter as a direct result of variations in the performance of our business, including those caused by fluctuations in commodity prices. Any such variations may be significant, and as a result, we may pay limited or even no cash distributions to our unitholders.

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. We spent approximately $302.8 million in 2023 on development costs and our budget for 2024 is between $250.0 million and $275.0 million. For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2024 is anticipated to focus on drilling Oswego wells given their high oil reserves and low breakeven costs.

During the year ended December 31, 2023, we spent approximately $261.6 million to drill 79.3 net wells and on related equipment, $28.8 million on remedial workovers and other capital projects, $12.4 million on midstream and other property and equipment capital projects, and $774.9 million on acquisitions.

Our 2024 capital expenditures program is largely discretionary and within our control. We could choose to defer a portion of these planned 2024 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, including acid to be used for our acid stimulation completion, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and reduce our cash available for distribution to unitholders.

Based on current oil and natural gas price expectations, we believe that our cash flow from operations, together with borrowings from time to time under the Revolving Credit Agreement, will be sufficient to fund our operations through 2024 and the foreseeable future. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled on drilling locations not classified as proved reserves in our December 31, 2023 reserve report. The failure to achieve anticipated production and cash flow from operations from such wells could result in a reduction in future capital spending and/or our ability to pay distributions to unitholders. We cannot assure you that operations and other needed capital will be available on acceptable terms or at all.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Year ended December 31,	
(in thousands)	**2023**	**2022**
Net cash provided by operating activities	$ 491,742	$ 553,542
Net cash used in investing activities	(1,027,157)	(372,660)
Net cash provided by (used in) financing activities	658,790	(210,737)

Net cash provided by operating activities.

Net cash provided by operating activities decreased $61.8 million for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The decrease in net cash provided by operating activities is primarily attributable to the decrease in realized pricing for all products. The decrease in realized pricing was partially offset with an increase in production from year to year. Additionally, we received $4.4 million in cash related to derivative settlements in 2023, compared to paying derivative settlements of $94.2 million in 2022, resulting in a net change of derivative settlements of $98.6 million.

Net cash used in investing activities.

Net cash used in investing activities increased $654.5 million for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The increase in net cash used in investing activities is primarily attributable to an increase in cash used in acquisitions of $621.0 million as well as an increase in capital expenditures on our oil and gas properties of $68.8 million from 2023 to 2022.

Net cash provided by (used in) financing activities.

Net cash provided by (used in) financing activities increased $869.5 million for the year ended December 31, 2023, as compared to the year ended December 31, 2022. The increase in net cash provided by financing activities is primarily attributable to an increase in proceeds from borrowings, net of repayments and issuance costs, of $638.8 million, as well as cash increase in cash received from the issuance of units in the Offering, net of repurchases of exchanging members of $102.2 million. Additionally, there was a decrease in distributions to members of the Company prior to the Offering of $173.5 million in 2023 in comparison to 2022.

Debt Agreements

Our Predecessor, BCE-Mach and BCE-Mach II were party to revolving credit facilities. We used a portion of the net proceeds from our initial public offering to (i) repay in full the BCE-Mach Credit Facility, (ii) repay in full the BCE-Mach II Credit Facility and (iii) repay a portion of the BCE-Mach III Credit Facility. On November 10, 2023, we entered into the November 2023 Credit Facility, and we used borrowings under the November 2023 Credit Facility to repay the BCE-Mach III Credit Facility in full and terminate each of the Pre-IPO Credit Facilities.

Prior Credit Facilities

BCE-Mach III Credit Facility. BCE-Mach III entered into a credit agreement for a revolving credit facility with a syndicate of banks, including MidFirst Bank, who served as administrative agent and issuing bank. The BCE-Mach III Credit Facility provided for a maximum outstanding amount of $400.0 million, subject to commitments of $100.0 million as of November 10, 2023. The BCE-Mach III Credit Facility was scheduled to mature in May 2026. Outstanding obligations under the BCE-Mach III Credit Facility were secured by substantially all of BCE-Mach III's assets. The amount available to be borrowed under the BCE-Mach III Credit Facility was subject to a borrowing base that was redetermined semiannually each May and November in an amount determined by the lenders. As of November 10, 2023, there was $91.9 million outstanding under the BCE-Mach III Credit Facility, which was repaid and terminated when we entered into the November 2023 Credit Facility.

BCE-Mach Credit Facility. BCE-Mach entered into a revolving credit facility with a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger, maturing in September 2026. Outstanding obligations under the BCE-Mach Credit Facility were secured by substantially all of BCE-Mach's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $200.0 million, subject to commitments of $100.0 million as of October 25, 2023. As of October 25, 2023, $65.0 million was outstanding under the BCE-Mach Credit Facility along with $5.0 million in outstanding letters of credit, which reduced the availability under the credit facility on a dollar-for-dollar basis. On November 10, 2023, the Company repaid all amounts outstanding under the BCE-Mach Credit Facility and entered into the November 2023 Credit Facility and terminated the BCE-Mach Credit Facility.

BCE-Mach II Credit Facility. BCE-Mach II entered into a revolving credit facility with a syndicate of banks, including East West Bank, who served as sole book runner and lead arranger, maturing in September 2024. Outstanding obligations under the BCE-Mach II Credit Facility were secured by substantially all of BCE-Mach II's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $250.0 million, subject to a borrowing base of $26.0 million as of October 25, 2023. As of October 25, 2023, $17.1 million was outstanding under the BCE-Mach II Credit Facility. On October 31, 2023, the Company repaid all amounts outstanding under the BCE-Mach II Credit Facility. On November 10, 2023, the Company entered into the November 2023 Credit Facility and terminated the BCE-Mach II Credit Facility.

November 2023 Credit Facility

On November 10, 2023, Holdco entered into the November 2023 Credit Facility with a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger. Outstanding obligations under the November 2023 Credit Facility were secured by substantially all of Holdco's assets. In connection with entering into the November 2023 Credit Facility, each of the Pre-IPO Credit Facilities were terminated.

The aggregate principal amount of loans outstanding under the November 2023 Credit Facility as of November 10, 2023 was $130.0 million, which included $5.0 million of issued letters of credit. The November 2023 Credit Facility provided for a revolving credit facility in an aggregate maximum amount of $1.0 billion, with an initial borrowing base of $600.0 million, subject to commitments of $200.0 million. On December 28, 2023, we entered into the Term Loan Credit Agreement and Revolving Credit Agreement, as described below, and terminated the November 2023 Credit Facility.

Term Loan Credit Agreement and Revolving Credit Agreement

On December 28, 2023, the Company entered into (i) the Term Loan Credit Agreement with the lenders party thereto, Texas Capital Bank, as agent, and Chambers Energy Management, LP, as the arranger, and (ii) the Revolving Credit Agreement with the lenders party thereto and MidFirst Bank as the agent.

Loans advanced to the Company under the Term Loan Credit Agreement are secured by a first-priority security interest on substantially all of our assets. The Term Loan Credit Agreement has (i) an aggregate principal amount of $825.0 million, (ii) a maturity date of December 31, 2026 and (iii) an interest rate equal to the three-month SOFR plus 6.50% plus a credit spread adjustment equal to 0.15%, provided that the three-month SOFR will not be less than 3.00%. Mandatory repayments of principal of $61.9 million, $82.5 million, and $680.6 million are due in the year 2024, 2025, and 2026, respectively. The Term Loan Credit Agreement includes customary covenants, mandatory repayments and events of default of financings of this type.

Loans advanced to the Company under the Revolving Credit Agreement are secured by a super-priority security interest on substantially all of our assets. The Revolving Credit Agreement has (i) a maximum available principal amount of $75.0 million, (ii) a maturity date of December 28, 2026 and (iii) an interest rate equal to one, three, or six month SOFR, at the Company's election, plus a credit spread adjustment equal to 0.10%, 0.15% or 0.25%, respectively, in each case, plus 3.00%, provided that the applicable tenor SOFR will not be less than 3.50%. The Revolving Credit Agreement includes customary covenants, mandatory repayments and events of default of financings of this type. The Company used borrowings from the Term Loan Credit Agreement, together with cash on hand, to repay the November 2023 Credit Facility. As of December 31, 2023, the Revolving Credit Agreement was undrawn, and there was $5.0 million in outstanding letters of credit.

We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in consolidated debt or losses.

Contractual Obligations and Commitments

Firm transportation contracts

We are a party to firm transportation contracts for the transport of natural gas. We paid approximately $1.0 million in firm transportation contracts for the year ended December 31, 2023 and expect to pay approximately $7.0 million in firm transportation contracts through 2025. For further information on firm transportation contracts, see the notes to our audited financial statements included in Item 8 of Part II of this Annual Report.

Operating lease obligations

Our operating lease obligations include long-term lease payments for office space, vehicles, equipment related to exploration, development and production activities. We paid approximately $14.3 million in operating lease payments for the year ended December 31, 2023 and expect to pay approximately $18.3 million in operating lease payments through 2027. For further information on our operating lease obligations, see the notes to our audited financial statements included in Item 8 of Part II of this Annual Report.

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.

Oil and Natural Gas Accounting and Reserves

We account for our oil and natural gas producing activities using the full cost method of accounting, which is dependent on the estimation of proved reserves to determine the rate at which we record depletion on our oil and natural gas properties. On a quarterly basis, using the estimate of proved reserves, we evaluate our oil and natural gas properties to determine whether they have been impaired using the full cost ceiling impairment test. Further, we utilize estimated proved reserves to assign fair value to acquired proved oil and natural gas properties. As such, we consider the estimation of proved reserves to be a critical accounting estimate.

Estimates of natural gas and oil reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See Note 16 of our consolidated financial statements for further information.

Business Combinations

We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 — Business Combinations, and involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based on the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values.

The most significant assumptions relate to the estimated fair values assigned to our proved oil and natural gas properties. The assumptions made in performing these valuations include future production volumes, future commodity prices and costs, future operating and development activities, projections of oil and gas reserves and a weighted average cost of capital rate. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings. See Note 3 of our consolidated financial statements for further discussion of business combinations.

Recently Issued Accounting Pronouncements

A summary of recent accounting pronouncements and our assessment of any expected impact of these pronouncements, if known, is included in Note 2 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses.

Commodity Price Risk

Oil and gas revenue

Our revenue and cash flow from operations are subject to many variables, the most significant of which is the volatility of commodity prices. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by global economic factors, pipeline capacity constraints, inventory levels, basis differentials, weather conditions and other factors. Commodity prices have long been volatile and unpredictable, and we expect this volatility to continue in the future.

There can be no assurance that commodity prices will not be subject to continued wide fluctuations in the future. A substantial or extended decline in such prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and gas reserves that may be economically produced, which could result in impairments of our oil and natural gas properties.

Commodity derivative activities

To reduce the impact of fluctuations of commodity prices on our total revenue and other operating income, we have historically used, and we expect to continue to use, commodity derivative instruments, primarily swaps, to hedge price risk associated with a portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in prices and may partially limit our potential gains from future increases in prices. We do not enter derivative contracts for speculative trading purposes. The Credit Agreements contain various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

Our hedging activities are intended to support oil and natural gas prices at targeted levels and manage our exposure to natural gas price volatility. Under swap contracts, the counterparty is required to make a payment to us for the difference between the swap price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the swap price. We are required to make a payment to the counterparty for the difference between the swap price and the settlement price if the swap price is below the settlement price. See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this Annual Report for further information on our open derivative positions.

Counterparty and Customer Credit Risk

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of a contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2023, we had derivative instruments in place with three different counterparties, with Morgan Stanley accounting for approximately 89% of the fair value. We believe our counterparties currently represent acceptable credit risks. We are not required to provide credit support or collateral to our counterparties under current contracts, nor are they required to provide credit support or collateral to us.

Substantially all of our revenue and receivables result from oil and gas sales to third parties operating in the oil and gas industry. Our receivables also include amounts owed by joint interest owners in the properties we operate. Both our purchasers and joint interest partners have recently experienced the impact of significant commodity price volatility as discussed above under "— Commodity Price Risk — Oil and Gas Revenue." This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in commodity prices and economic and other conditions. In the case of joint interest owners, we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings.

Interest Rate Risk

Variable rate debt

At December 31, 2023, we had $825.0 million of debt outstanding under the Term Loan Credit Agreement. Borrowings outstanding under the Term Loan Credit Agreement bore an effective interest rate of 13.1% as of December 31, 2023. Assuming no change in the amount outstanding, the impact on interest expense of a 1% (or 100 basis points) increase or decrease in the assumed weighted average interest rate on our variable interest debt would be approximately $8.3 million per year based on our borrowings outstanding at December 31, 2023.

Interest rate derivative activities

As of December 31, 2023, we did not have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness, but we may enter into such derivative arrangements in the future. To the extent we enter into any such interest rate derivative arrangement, we would be subject to risk for financial loss.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS
MACH NATURAL RESOURCES LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
Mach Natural Resources LP

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Mach Natural Resources LP (a Delaware limited partnership) and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, partners' capital and members' equity, and cash flows for each of the three years in the period ended December 31, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with 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 standardsof the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2018.

Oklahoma City, Oklahoma
April 1, 2024

MACH NATURAL RESOURCES LP
CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31, 2023	As of December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 152,792	$ 29,417
Accounts receivable – joint interest and other, net	54,155	21,797
Accounts receivable – oil, gas, and NGL sales	78,051	108,277
Short-term derivative assets	24,802	—
Inventories	31,377	24,700
Other current assets	2,425	2,459
Total current assets	343,602 343,602	186,650
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	2,097,540	749,934
Less: accumulated depreciation, depletion and amortization	(265,895)	(139,514)
Oil and natural gas properties, net	1,831,645	610,420
Other property, plant and equipment	105,302	82,125
Less: accumulated depreciation	(15,642)	(9,198)
Other property, plant and equipment, net	89,660	72,927
Long-term derivative assets	15,112	—
Other assets	7,102	3,052
Operating lease assets	17,394	14,809
Total assets	$ 2,304,515	$ 887,858
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 44,577	$ 19,429
Accounts payable – related party	2,867	417
Accrued liabilities	44,529	60,169
Revenue payable	110,296	52,196
Short-term derivative liabilities	—	10,080
Current portion of long-term debt	61,875	—
Current portion of operating lease liabilities	10,765	10,767
Total current liabilities	274,909	153,058
Long-term debt	745,140	84,900
Asset retirement obligations	85,094	52,359
Long-term portion of operating leases	6,705	4,042
Other long-term liabilities	943	269
Total long-term liabilities	837,882	141,570
Commitments and contingencies (Note 10)		
Partners’ capital and members’ equity:		
Partners’ capital	1,191,724	—
Members’ equity	—	593,230
Total liabilities and partners’ capital and members’ equity	$ 2,304,515	$ 887,858

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per common unit data)

	Year Ended December 31,		
	2023	**2022**	**2021**
Revenue			
Oil, natural gas, and NGL sales	$ 647,352	$ 860,388	$ 397,500
Gain (loss) on oil and natural gas derivatives	57,272	(67,453)	(67,549)
Midstream revenue	26,328	44,373	31,883
Product sales	31,357	100,106	30,663
Total revenues	762,309	937,414	392,497
Operating expenses			
Gathering and processing	39,449	47,484	27,987
Lease operating expense	127,602	95,941	45,391
Production taxes	31,882	47,825	21,165
Midstream operating expense	10,873	15,157	12,248
Cost of product sales	28,089	94,580	28,687
Depreciation, depletion, amortization and accretion – oil and natural gas	131,145	84,070	37,537
Depreciation and amortization – other	6,472	4,519	3,148
General and administrative	22,861	23,491	60,927
General and administrative – related party	4,792	1,963	—
Total operating expenses	403,165	415,030	237,090
Income from operations	359,144	522,384	155,407
Other (expense) income			
Interest expense	(11,201)	(4,852)	(1,656)
Other (expense) income, net	(1,385)	(691)	1,023
Loss on contingent consideration	—	—	(16,400)
Total other expense	(12,586)	(5,543)	(17,033)
Net income	346,558	$ 516,841	$ 138,374
Less: net income attributable to Predecessor	(278,040)		
Net income attributable to Mach Natural Resources LP	$ 68,518		
Net income per common unit attributable to Mach Natural Resources LP			
Basic	$ 0.72		
Diluted	$ 0.72		
Weighted average common units outstanding:			
Basic	94,907		
Diluted	94,907		

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL AND MEMBERS' EQUITY
(in thousands)

	Predecessor	Mach Natural Resources LP		
	Members' Equity	Common Units	Partners' Capital	Total Partners' Capital and Members' Equity
Balance at December 31, 2020	$ 139,561	—	$ —	$ 139,561
Contributions	101,461	—	—	101,461
Distributions	(146,000)	—	—	(146,000)
Equity compensation	45,303	—	—	45,303
Net income	138,374	—	—	138,374
Balance at December 31, 2021	$ 278,699	—	$ —	$ 278,699
Contributions	65,000	—	—	65,000
Distributions	(274,837)	—	—	(274,837)
Equity compensation	7,527	—	—	7,527
Net income	516,841	—	—	516,841
Balance at December 31, 2022	$ 593,230	—	$ —	$ 593,230
Contributions	20,000	—	—	20,000
Distributions	(101,350)	—	—	(101,350)
Equity compensation	2,595	—	—	2,595
Net income prior to the Corporate Reorganization	278,040	—	—	278,040
Common units issued in Corporate Reorganization to Existing Owners of BCE-Mach III LLC (Note 1)	(792,515)	76,769	792,515	—
Common units issued for the acquisitions of BCE-Mach I LLC and BCE-Mach II LLC (Note 3)	—	11,981	227,644	227,644
Common units issued in the Offering, net of underwriting fees and offering expenses (Note 1)	—	10,000	168,465	168,465
Common units repurchased from Exchanging Members (Note 1)	—	(3,750)	(66,263)	(66,263)
Equity compensation subsequent to the Corporate Reorganization	—	—	845	845
Net income subsequent to the Corporate Reorganization	—	—	68,518	68,518
Balance at December 31, 2023	$ —	95,000	$ 1,191,724	$ 1,191,724

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31,		
	2023	**2022**	**2021**
Cash flows from operating activities			
Net income	$ 346,558	$ 516,841	$ 138,374
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation, depletion and amortization	137,617	88,589	40,685
(Gain) loss on derivative instruments	(57,272)	67,453	67,549
Cash receipts (payments) on settlement of derivative contracts, net	4,417	(94,201)	(59,381)
Debt issuance costs amortization	1,950	375	312
Loss on contingent consideration	—	—	16,400
Settlement of contingent consideration	—	(13,547)	(9,553)
Equity based compensation	3,440	7,527	45,303
Credit losses	1,746	—	—
Gain on sale of assets	(1)	(45)	(85)
Settlement of asset retirement obligations	(537)	(49)	(35)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable, inventories, other assets	29,065	(30,671)	(74,462)
Revenue payable	19,029	(908)	24,389
Accounts payable and accrued liabilities	5,730	12,178	8,966
Net cash provided by operating activities	491,742	553,542	198,462
Cash flows from investing activities			
Capital expenditures for oil and natural gas properties	(302,376)	(233,584)	(37,789)
Capital expenditures for other property and equipment	(12,428)	(9,441)	(3,219)
Acquisition of assets	(754,847)	(96,620)	(154,419)
Acquisition of assets – related party	—	(37,242)	—
Cash acquired from the acquisition of businesses	39,153	—	—
Proceeds from sales of oil and natural gas properties	3,305	3,996	599
Proceeds from sales of other property and equipment	36	231	85
Net cash used in investing activities	(1,027,157)	(372,660)	(194,743)
Cash flows from financing activities			
Proceeds from borrowings on term note	811,000	—	—
Proceeds from issuance of units in the Offering	168,465	—	—
Purchases of units from exchanging members	(66,263)	—	—
Proceeds from borrowings on credit facility	68,000	—	72,900
Repayments of borrowings on credit facility	(235,000)	(900)	(30,800)
Debt issuance costs	(6,062)	—	(245)
Contributions from members	20,000	65,000	101,461
Distributions to members	(101,350)	(274,837)	(146,000)
Settlement of contingent consideration	—	—	(1,900)
Net cash provided by (used in) financing activities	658,790	(210,737)	(4,584)
Net increase (decrease) in cash and cash equivalents	123,375	(29,855)	(865)
Cash and cash equivalents, beginning of period	29,417	59,272	60,137
Cash and cash equivalents, end of period	$ 152,792	$ 29,417	$ 59,272

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

MACH NATURAL RESOURCES LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.)

Unless otherwise stated or the context otherwise indicates, all references to the "Company" for time periods prior to the Corporate Reorganization refer to BCE-Mach III LLC and its subsidiary, the Company's predecessor for accounting purposes. For time periods subsequent to the Corporate Reorganization, this term refers to Mach Natural Resources LP and its subsidiaries.

1. Nature of Business

Mach Natural Resources LP ("the Company") is a Delaware limited partnership that was formed for the purpose of effectuating an initial public offering (the "Offering") that closed in October 2023. The Company's common units representing limited partnership interests (the "common units") are listed on The New York Stock Exchange under the symbol "MNR." The Company is an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas.

Following the Offering and Corporate Reorganization, the Company became a holding partnership whose sole material asset consists of membership interests in Mach Natural Resources Intermediate LLC ("Intermediate"). Intermediate wholly owns Mach Natural Resources Holdco LLC ("Holdco"), and Holdco wholly owns each of the Company's three operating subsidiaries, BCE-Mach LLC ("BCE-Mach"), BCE-Mach II LLC ("BCE-Mach II") and BCE-Mach III LLC (collectively, the "Mach Companies"). BCE-Mach III LLC (the "Predecessor") is the accounting predecessor to the Company for all periods prior to the Offering as discussed herein.

The Company's operations are governed by the provisions of its partnership agreement, executed by its general partner, Mach Natural Resources GP LLC (the "General Partner") and the limited partners. The General Partner is managed and operated by the board of directors and executive officers of the General Partner. The members of the board of directors of the General Partner are appointed by the members of the General Partner, BCE-Mach Aggregator and Mach Resources in proportion to their respective limited partnership ownership in the Company.

Management has evaluated how the Company is organized and managed and identified a single reportable segment, which is the exploration and production of oil, natural gas and NGLs. Management considers the Company's gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and its revenues are attributable to United States customers.

Corporate Reorganization

On October 25, 2023, the Company underwent a corporate reorganization (the "Corporate Reorganization") whereby (a) the owners who directly held membership interests in the Mach Companies prior to the Offering (the "Existing Owners") contributed 100% of their membership interests in each of the Mach Companies for a pro rata allocation of 100% of the limited partner interests in the Company with BCE-Mach III determined as the accounting acquirer of the net assets and operations of BCE-Mach and BCE-Mach II through a business combination, (b) the Company contributed 100% of its membership interests in the Mach Companies to Intermediate in exchange for100% of the membership interests in Intermediate, and (c) Intermediate contributed 100% of its membership interests in the Mach Companies to Holdco in exchange for100% of the membership interests in Holdco.

Initial Public Offering

On October 27, 2023, the Company completed the Offering of10,000,000 common units at a price of $19.00 per unit to the public. The sale of Company's common units resulted in gross proceeds of $190.0 million to the Company and net proceeds of $168.5 million, after deducting underwriting fees and offering expenses. The material terms of the Offering are described in the Company's final prospectus, filed with the U.S. Securities and Exchange Commission ("SEC") on October 26, 2023, pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended (the "Securities Act").

The Company used $102.2 million of the proceeds to pay down the existing credit facilities of its operating subsidiaries (the "Pre-IPO Credit Facilities") and $66.3 million of the proceeds to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis. After giving effect to the Offering and the transactions related thereto, the Company had 95,000,000 common units issued and outstanding.

2. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP") and include accounts of our wholly owned subsidiaries. Intercompany accounts and transactions have been eliminated upon consolidation. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Our historical financial data as of and for the year ended December 31, 2022, reflects BCE-Mach III LLC, the accounting predecessor of Mach Natural Resources LP. Our financial and operating data for the year ended December 31, 2023 includes BCE-Mach III for the entire period and BCE-Mach LLC and BCE-Mach II LLC from October 25, 2023, the effective date of the acquisition as a result of the Corporate Reorganization.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities assumed in business combinations and the fair value estimates of commodity derivatives.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial effect on the previously reported total assets, total liabilities, partners' capital, results of operations or cash flows.

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 financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable primarily consists of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for credit losses. The Company extends credit to joint interest owners and generally does not require collateral, but typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due.

The Company establishes its allowance for credit losses equal to the estimable portions of accounts receivable for which failure to collect is expected to occur primarily based on a historical loss rate analysis. The Company estimates uncollectible amounts based on a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's expected ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company considers forecasts of future economic conditions in its estimate of expected credit losses and adjusts its allowance for expected credit losses when necessary. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for credit losses. At December 31, 2023 the allowance for credit losses related to joint interest receivables was $1.7 million, and the credit losses related to sales of oil and natural gas properties were not material.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments in the statement of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $6.86, $5.18 and $3.46 for the years ended December 31, 2023, 2022 and 2021, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $126.4 million, $80.5 million and $35.8 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Under the full cost method, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each reporting period. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and natural gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on a quarterly basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the IRS recognition of the Company as a flow-through entity. No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2023, 2022 and 2021.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. As of December 31, 2023, and December 31, 2022, the Company had no properties excluded from the full cost pool. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas, and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of a gathering system, processing plant, and salt water disposal system. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from two to 39 years. Depreciation expense for other property and equipment was $6.5 million, $4.5 million and $3.1 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment was recorded for the years ending December 31, 2023, 2022 and 2021.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production and midstream equipment not placed in service as of December 31, 2023, and 2022. The Company's production equipment primarily comprises oil and natural gas drilling or repair items such as tubing, casing and pumping units, as well as pipe for midstream operations.

Debt Issuance Costs

Other assets include capitalized costs related to the Revolving Credit Agreement of $2.2 million, net of accumulated amortization of $1.6 million as of December 31, 2023. As of December 31, 2022, other assets include capitalized costs related to the BCE-Mach III Credit Facility of $1.0 million, net of accumulated amortization of $0.8 million. These costs are being amortized over the terms of the related credit agreements and are reported as interest expense on the Company's statements of operations.

Debt issuance costs and the discount associated with the Company's term loan are presented as a reduction of the carrying value of long-term debt on the Company's balance sheet. As of December 31, 2023, the Company had unamortized debt issuance costs and discount of $18.0 million in relation to the term loan.

Income Taxes

The Company is a limited partnership treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company passed through to partners. As such, with the exception of the state of Texas, we are not a taxable entity, we do not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for our operations, except as described below.

Limited partnerships are subject to state income taxes in the state of Texas. Due to immateriality, income taxes related to the Texas franchise tax have been included in general and administrative expenses on the statement of operations and no deferred tax amounts were calculated.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company did not recognize any potential interest or penalties in its financial statements for the year ended December 31, 2023. The Company's tax years 2022, 2021 and 2020 remain open for examination by state authorities.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction or salt water disposal began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO activity for the years ended December 31, 2023 and 2022 (in thousands):

	Year Ended December 31,	
	2023	2022
Asset retirement obligation at beginning of period	$ 52,359	$ 25,620
Liabilities assumed in acquisitions	27,637	21,385
Liabilities incurred	518	1,660
Liabilities settled	(497)	(136)
Liabilities revised	313	218
Accretion expense	4,764	3,612
Asset retirement obligation at end of period	$ 85,094	$ 52,359

Revenue Recognition

Sales of oil, natural gas and NGLs are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 7 for the Company's management of price volatility.

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statement of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGL are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statement of operations.

Midstream Revenue and Product Sales

The Company's gathering and processing revenue is generated from owned gathering and compression systems and processing plants acquired in the Company's acquisitions. The Company charges a gathering, compression, processing rate per MMBtu transported through the gathering system and processing plant. The Company also gathers and disposes of salt water from producing wells through an owned pipeline system and disposal wells. The Company charges a fixed rate per barrel of water for disposal. Fees are recognized as revenue based on measured volume at the specified delivery points when the associated service is performed.

Product sales are generated from the Company's sale of natural gas, oil and NGL production purchased from third parties and subsequently gathered and processed through the Company's owned midstream facilities. Product sales includes activity from certain third-party percent-of-proceeds contracts where the Company keeps a contractually based percentage of proceeds from the sale of natural gas and NGL production, as payment for processing natural gas from the third parties. The Company retains control of the purchased natural gas and NGLs prior to delivery to the purchaser and satisfies its performance obligations by transferring control of the product at the delivery point and recognizes revenue based on the contract price received from the purchaser. The costs of buying natural gas, oil and NGL production from third party shippers are included as costs of product sales on the statement of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it 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 the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Each unit of product delivered to the customer 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.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers.The following purchasers each accounted for more than 10% of the Company's revenues for the periods indicated:

	Year Ended December 31,		
	2023	2022	2021
Hinkle Oil and Gas Inc.	*	31.5 %	13.3 %
NextEra Energy Marketing, LLC	12.9 %	17.0 %	20.2 %
Philips 66 Company	52.6 %	16.9 %	33.5 %
ONEOK Hydrocarbon L.P.	10.4 %	*	13.9 %

* Purchaser did not account for greater than 10% of oil, natural gas, and NGL sales for the year.

The Company's receivables as of December 31, 2023 and 2022 from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

As of December 31, 2023 the Company had three customers that represented approximately23.5%, 16.2%, and 12.6% of our total joint interest receivables. As of December 31, 2022 the Company had one customer that represented approximately 20.8% of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Revenues:			
Oil	$ 421,737	$ 447,997	$ 189,390
Natural gas	150,962	300,785	131,784
NGL	74,815	109,756	75,081
Gross oil, natural gas, and NGL sales	647,514	858,538	396,255
Transportation, gathering and marketing	(162)	1,850	1,245
Net oil, natural gas, and NGL sales	$ 647,352	$ 860,388	$ 397,500

Earnings per Common Unit

The Company’s basic earnings per unit (“EPU”) is computed based on the weighted average number of common units outstanding for the period. Diluted EPU includes the effect of the Company’s phantom units if the inclusion of these units is dilutive. See Note 13 for additional information on the Company’s EPU.

Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Year ended December 31,		
	2023	2022	2021
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 8,373	$ 4,339	$ 1,150
Non-cash investing and financing activities:			
Change in accrued capital expenditures	$ (19,104)	$ 29,363	$ 12,392
Asset retirement cost capitalized	$ 518	$ 1,660	$ 240
Right-of-use assets obtained in exchange for lease liabilities	$ 10,767	$ 22,266	$ —
Equity issued in exchange for net assets acquired in business combinations	$ 227,644	$ —	$ —

Recent Accounting Pronouncements Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, “Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments,” which amended reporting guidance on credit losses for certain financial instruments. The Company’s primary risk for credit losses relates to our receivables from joint interest owners in our operated oil and natural gas wells. This guidance was effective for periods after December 15, 2022, and the Company implemented it effective January 1, 2023, with no material impacts to our consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

In November 2023, the FASB issued ASU 2023-07, “Segment Reporting (Topic 280) – Improvements to Reportable Segment Disclosures,” which updates reportable segment disclosure requirements primarily through enhanced disclosures about significant segment expenses and information used to assess segment performance. The amendments are effective for annual periods beginning after December 15, 2023, and for interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. The amendments should be applied retrospectively to all prior periods presented in the financial statements. Management is currently evaluating this ASU to determine its impact on the Company's disclosures. Adoption of the update will not impact the Company’s financial position, results of operations or liquidity.

3. Acquisitions

2023 Acquisitions

Paloma Partners IV, LLC

On November 10, 2023, the Company entered into a purchase and sale agreement (the "Paloma PSA") with Paloma Partners IV, LLC pursuant to which the Company agreed to purchase certain interests in oil and gas properties, rights and related assets located in Blaine, Caddo, Canadian, Custer, Dewey, Grady, Kingfisher and McClain Counties, Oklahoma (the "Paloma Assets").
On December 28, 2023, the Company completed the acquisition of the Paloma Assets (the "Paloma Acquisition") in accordance with the terms of the Paloma PSA for a purchase price of approximately $815,000,000 in cash. The Paloma PSA provides for customary post-closing adjustments to the purchase price based on an effective date of September 1, 2023. The Company expects to finalize all such adjustments and complete the purchase price allocation during the second quarter of 2024 based on the terms of the Paloma PSA. The Company does not expect post-closing adjustments to be material and they would affect the value of proved oil and gas properties. The Company utilized borrowings under the Term Loan Credit Agreement to fund the Paloma Acquisition.

The Paloma Acquisition was accounted for as an asset acquisition as substantially all of the gross fair value of the Paloma Assets was concentrated in proved oil and natural gas properties, which were considered to be a group of similar identifiable assets. The table below reflects the preliminary fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. While the preliminary purchase price allocation is substantially complete, there may be further adjustments to the assets acquired and liabilities assumed in the Paloma Acquisition. These amounts will be finalized within the measurement period of the acquisition which will be no later than one year from the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of assets acquired and liabilities assumed (in thousands):

	Paloma Acquisition
Consideration transferred:	
Cash consideration	$ 748,587
Capitalized transaction costs	1,695
Less: purchase price adjustment receivable	(15,160)
Total acquisition consideration	735,122
Assets acquired:	
Accounts receivable	4,239
Inventories	166
Proved oil and natural gas properties	750,476
Total assets to be acquired	754,881
Liabilities assumed:	
Revenue payable	18,295
Asset retirement obligations	1,464
Total liabilities assumed	19,759
Net assets acquired	$ 735,122

BCE-Mach LLC and BCE-Mach II LLC

On October 25, 2023, as part of the Corporate Reorganization, the Existing Owners contributed all of their equity interests in BCE-Mach, BCE-Mach II and the Predecessor to the Company in exchange for 100% of the limited partnership interests in the Company to effectuate the acquisition. While there was a high degree of common ownership, the Mach Companies were not under common control for financial reporting purposes. The Predecessor was identified as the accounting acquirer of BCE-Mach and BCE-Mach II which have been accounted for as business combinations under the acquisition method of accounting under U.S. GAAP.

The following table presents the fair value of consideration transferred by the Company for each of the acquisitions (amounts in thousands, except unit and per unit amounts):

	BCE-Mach	BCE-Mach II
Common units issued for acquisition	7,765,625	4,215,625
Offering price of common units	$ 19.00	$ 19.00
Total acquisition consideration	$ 147,547	$ 80,097

The tables below reflect the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below are reconciliations of assets acquired and liabilities assumed from the initial disclosure to final purchase price allocations (in thousands):

	Initial BCE-Mach	Adjustments		Final BCE-Mach
Assets acquired:				
Cash and cash equivalents	$ 25,370	$ 4,980	(a)	$ 30,350
Accounts receivable	32,573	(531)	(a)	32,042
Other current assets	16,605	1,698	(a)	18,303
Proved oil and natural gas properties	174,915	9,925	(b)	184,840
Other long-term assets	12,381	(1,205)	(a)	11,176
Total assets to be acquired	261,844	14,867		276,711
Liabilities assumed:				
Accounts payable and accrued liabilities	16,900	412	(a)	17,312
Revenue payable	28,808	582	(a)	29,390
Other current liabilities	1,754	(393)	(a)	1,361
Long-term debt	65,000	—	(a)	65,000
Asset retirement obligations	—	14,369	(b)	14,369
Other long-term liabilities	1,835	(103)	(a)	1,732
Total liabilities assumed	114,297	14,867		129,164
Net assets acquired	$ 147,547	$ —		$ 147,547

	Initial BCE-Mach II	Adjustments		Final BCE-Mach II
Assets acquired:				
Cash and cash equivalents	$ 9,127	$ (324)	(a)	$ 8,803
Accounts receivable	11,312	229	(a)	11,541
Other current assets	2,236	95	(a)	2,331
Proved oil and natural gas properties	87,991	10,809	(b)	98,800
Other long-term assets	7,655	156	(a)	7,811
Total assets to be acquired	118,321	10,965		129,286
Liabilities assumed:				
Accounts payable and accrued liabilities	4,192	(533)	(a)	3,659
Revenue payable	15,370	(53)	(a)	15,317
Other current liabilities	450	(4)	(a)	446
Long-term debt	17,100	—	(a)	17,100
Asset retirement obligations	—	11,589	(b)	11,589
Other long-term liabilities	1,112	(34)	(a)	1,078
Total liabilities assumed	38,224	10,965		49,189
Net assets acquired	$ 80,097	$ —		$ 80,097

a. Adjustment reflects finalization of accounting data as of the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

b. Asset retirement costs were presented net of proved oil and gas properties in the initial purchase price allocation. Adjustment reflects the presentation to separately present the assumed asset retirement liability.

The results of operations attributable to the BCE-Mach acquisition from the acquisition date through December 31, 2023 have been included in the consolidated statement of operations for the year ended December 31, 2023, and include $26.3 million of total revenue and $6.8 million of net income. The results of operations attributable to the BCE-Mach II acquisition from the acquisition date through December 31, 2023 have been included in the consolidated statement of operations for the year ended December 31, 2023, and include $5.1 million of total revenue and $22 thousand of net income.

Hinkle Oil and Gas, Inc.

On June 28, 2023 the Company executed a purchase and sale agreement with Hinkle Oil and Gas, Inc. for the sale of certain oil and gas properties in Oklahoma for $20.0 million, subject to certain customary adjustments. The transaction closed on August 11, 2023. This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties.

Business Combination Pro Forma Disclosures

The following table summarizes the unaudited pro forma consolidated financial information of the Company as if the business combinations of BCE-Mach and BCE-Mach II had occurred on January 1, 2022 (in thousands):

	Year Ended December 31,	
	2023	2022
Total revenues	$ 914,400	$ 1,197,036
Net income	351,967	610,415

The unaudited pro forma financial information is not necessarily indicative of the operating results that would have occurred had the business combinations been completed on January 1, 2022 and is not necessarily indicative of future results of operations of the combined company. The unaudited pro forma financial information gives effect to the business combinations that occurred during 2023 as if the transactions had occurred on January 1, 2022. The unaudited pro forma financial information for the years ended December 31, 2023 and 2022 is a result of combining the statements of operations of the Company with the pre-acquisition results of BCE-Mach and BCE-Mach II, with pro forma adjustments for revenues and expenses. The unaudited pro forma financial information excludes any anticipated cost savings as a result of the acquisitions.

The unaudited pro forma financial information includes the following adjustments:

- For the year ended December 31, 2023: Increased depreciation, depletion and accretion-oil and gas of $27.8 million and reduced depreciation and amortization-other of $7.4 million

- For the year ended December 31, 2022: Increased depreciation, depletion and accretion-oil and gas of $16.7 million and reduced depreciation and amortization-other of $8.1 million

Management believes the estimates and assumptions are reasonable, and the effects of the acquisition are properly reflected.

2022 Acquisitions

Camino Natural Resources, LLC

On May 17, 2022, the Company executed a purchase and sale agreement with Camino Natural Resources, LLC for the sale of certain oil and natural gas properties in Oklahoma for $22.0 million subject to certain adjustments. The transaction closed on June 30, 2022 and was effective as of January 1, 2022. The acquisition was funded through contributions from members and operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and natural gas properties of $15.8 million, net of asset retirement obligations assumed of $2.2 million and revenue suspense liabilities of $0.4 million. Cash paid for assets as of December 31, 2023 was $15.4 million.

Scout Energy, LP

On May 6, 2022, the Company executed a purchase and sale agreement with Scout Energy Group I, LP and other affiliates for the sale of certain oil and natural gas properties in Oklahoma and Texas for $66.0 million subject to certain adjustments. The transaction closed on June 30, 2022 and was effective as of March 1, 2022. The acquisition was funded through contributions from members and operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. The fair value of the midstream assets was assessed using a variety of valuation techniques including the income and cost approach. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

Assets acquired and liabilities assumed	
Oil and natural gas properties	$ 69,103
Other property and equipment	3,000
Other assets	147
Revenue suspense	(1,415)
Asset retirement obligations assumed	(11,841)
Total assets acquired, net of liabilities assumed	$ 58,994

Cash paid for assets as of December 31, 2023 was $59.0 million.

Woolsey Energy Corporation

On December 1, 2021, the Company executed a purchase and sale agreement with Woolsey Energy Corporation and other affiliates for the sale of certain oil and natural gas properties in Kansas, Oklahoma, and Texas for $26.0 million subject to certain adjustments. The transaction closed on January 31, 2022 and was effective as of December 1, 2021. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and natural gas properties of $23.2 million, net of asset retirement obligations assumed of $6.4 million, and inventory of $1.5 million. Cash paid for assets as of December 31, 2023 was $24.7 million.

BCE-Stack Development LLC

On November 12, 2021, the Company executed a purchase and sale agreement with BCE-Stack Development LLC for the sale of certain oil and natural gas properties in Oklahoma for $40.5 million subject to certain adjustments. The transaction closed on February 28, 2022 and was effective as of January 1, 2022. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and natural gas properties of $37.2 million, net of asset retirement obligations assumed of $0.5 million. Cash paid for assets as of December 31, 2023 was $37.2 million.

2021 Acquisitions

Chisholm Oil and Gas Operating, LLC

On December 30, 2021, the Company executed a purchase and sale agreement with Chisholm Oil and Gas Operating, LLC for the sale of certain oil and natural gas properties in Oklahoma for $33.0 million subject to certain adjustments. The transaction closed on December 31, 2022 and was effective as of October 1, 2021. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and natural gas properties of $28.9 million, net of asset retirement obligations assumed of $1.1 million.

MEP Mid-Con III, LLC

On June 15, 2021, the Company executed a purchase and sale agreement with MEP Mid-Con III, LLC for the sale of certain oil and natural gas properties in Oklahoma for $34.0 million subject to certain adjustments. The transaction closed on July 29, 2021 and was effective as of March 1, 2021. The acquisition was primarily funded from equity contributions from its members. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and natural gas properties of $25.7 million, net of asset retirement obligations assumed of $0.1 million.

Cimarex Energy Co.

On April 26, 2021 the Company executed a purchase and sale agreement with Cimarex Energy Co. ("XEC") for the sale of certain oil and gas assets in Oklahoma and Texas, two gas processing plants, and a gathering system at a purchase price of $95.7 million, subject to certain adjustments. The transaction with XEC closed on June 18, 2021 and was effective as of March 1, 2021. The sale was primarily funded through contributions from its members. The purchase was accounted for as a business combination, under the acquisition method as the Company obtained control of a business by obtaining the legal right to use and develop the oil and natural gas properties included in the purchase and sale agreement, as well as additional oil and gas related assets that can be used to enhance the value of the business. The fair value of the oil and natural gas properties acquired was assessed by utilizing a fair value reserve report that used future pricing and other commonly used valuation techniques.

The fair value of the midstream assets was assessed using a variety of valuation techniques including the income and cost approach. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

Assets acquired and liabilities assumed		
Oil and natural gas properties	$	85,959
Other property and equipment		13,474
Inventory		122
Linefill		465
Gas imbalances		(149)
Revenue suspense		(931)
Asset retirement obligations assumed		(12,440)
Total assets acquired, net of liabilities assumed	$	86,500

4. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	As of December 31,			
	2023		2022	
Oil and natural gas properties				
Proved properties	$	2,097,540	$	749,934
Accumulated depreciation and depletion		(265,895)		(139,514)
Oil and natural gas properties, net	$	1,831,645	$	610,420
Other property and equipment				
Gas gathering system	$	32,873	$	24,713
Gas processing plants		34,888		33,858
Water disposal assets		26,088		21,029
Other assets		11,453		2,525
Total other property and equipment		105,302		82,125
Accumulated depreciation, depletion and amortization		(15,642)		(9,198)
Total other property and equipment, net	$	89,660	$	72,927

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	As of December 31,	
	2023	2022
Operating expenses	$ 15,686	$ 10,198
Capital expenditures	15,042	37,375
Payroll costs	5,989	2,450
Derivative settlements	—	898
Severance and other tax	3,438	3,662
Midstream shipper payable	1,247	5,157
General, administrative, and other	3,127	429
Total accrued liabilities	$ 44,529	$ 60,169

6. Long-Term Debt

Term Loan Credit Agreement and Revolving Credit Agreement

On December 28, 2023, the Company entered into (i) a senior secured term loan credit agreement (the “Term Loan Credit Agreement”) with the lenders party thereto, Texas Capital Bank, as agent, and Chambers Energy Management, LP, as arranger, and (ii) a senior secured revolving credit agreement (the “Revolving Credit Agreement,” and together with the Term Loan Credit Agreement, the “Credit Agreements”) with a syndicate of lenders, including MidFirst Bank as the administrative agent.

Loans advanced to the Company under the Term Loan Credit Agreement are secured by a first-priority security interest on substantially all of our assets. The Term Loan Credit Agreement has (i) an aggregate principal amount of $825.0 million, (ii) a maturity date of December 31, 2026 and (iii) an interest rate equal to the three-month SOFR plus 6.50% plus a credit spread adjustment equal to 0.15%, provided that the three-month SOFR will not be less than 3.00%. The Term Loan Credit Agreement includes customary covenants, mandatory repayments and events of default of financings of this type. Mandatory repayments of principal of $61.9 million, $82.5 million, and $680.6 million are due in the year 2024, 2025, and 2026, respectively. As of December 31, 2023, there were $825.0 million of outstanding borrowings under the Term Loan Credit Agreement. The effective interest rate as of December 31, 2023 was 13.1%.

Loans advanced to the Company under the Revolving Credit Agreement are secured by a super-priority security interest on substantially all of our assets. The Revolving Credit Agreement has (i) a maximum available principal amount of $75.0 million, with maximum commitments currently equal to $75.0 million, (ii) a maturity date of December 28, 2026 and (iii) an interest rate equal to the one, three, or six month SOFR, at the Company’s election, plus a credit spread adjustment equal to 0.10%, 0.15%, or 0.25%, respectively, in each case, plus 3.00%, provided that the applicable tenor SOFR will not be less than 3.50%. The Revolving Credit Agreement includes customary covenants, mandatory repayments and events of default of financings of this type. The Company used borrowings from the Term Loan Credit Agreement, together with cash on hand, to repay the November 2023 Credit Facility. As of December 31, 2023, the Revolving Credit Agreement was undrawn, and there was $5.0 million in outstanding letters of credit.

We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in consolidated debt or losses.

Prior Credit Facilities

BCE-Mach III Credit Facility

On May 19, 2020, the Predecessor entered into a credit agreement for a revolving credit facility (the “BCE-Mach III Credit Facility”) with a syndicate of banks, including MidFirst Bank (“MidFirst”), who served as administrative agent and issuing bank. The BCE-Mach III Credit Facility provided for a maximum of $300.0 million, subject to commitments of $100.0 million and was scheduled to mature in May 2026. Outstanding obligations under the BCE-Mach III Credit Facility were secured by substantially all of the Predecessor’s assets. The amount available to be borrowed under the BCE-Mach III

Credit Facility was subject to a borrowing base that was redetermined semiannually each May and November in an amount determined by the lenders. As of December 31, 2022, there was $84.9 million outstanding under the BCE-Mach III Credit Facility.

The credit agreement contained various affirmative, negative and financial maintenance covenants. These covenants, among other things, limited additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. The BCE-Mach III Credit Facility required mandatory payments when the consolidated cash balance of the Predecessor exceeded $20.0 million.

At the Predecessor's election, outstanding borrowings under the credit agreement bore interest at a per annum rate elected by the Predecessor that was equal to an alternative base rate (which was equal to the greatest of the most recent prime rate, the Federal Funds effective rate plus 0.5%, and 1-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranged from 2.0% to 3.0% in the case of the alternate base rate and from3.25% to 4.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding. The Predecessor was obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee was also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of December 31, 2022 was 7.7%.

On November 10, 2023, there was $91.9 million outstanding under the BCE-Mach III Credit Facility, which was repaid and terminated when the Company entered into the November 2023 Credit Facility. The termination of the BCE-Mach III Credit Facility was treated as a debt modification, due to the makeup of banks in each credit facility syndicate. The Company wrote off the issuance costs associated with banks exiting the credit facility, and evaluated the change in borrowing capacity with remaining syndicate members and determined no additional issuance cost write offs were necessary. Total write offs of issuance costs were $14 thousand, and were included in the Company's interest expense on the statement of operations.

BCE-Mach Credit Facility

On October 25, 2023, the Company assumed the revolving credit facility (the "BCE-Mach Credit Facility") between BCE-Mach and a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger. Outstanding obligations under the BCE-Mach Credit Facility were secured by substantially all of BCE-Mach's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $200.0 million, subject to commitments of $100.0 million. As of October 25, 2023, $65.0 million was outstanding under the BCE-Mach Credit Facility along with $5.0 million in outstanding letters of credit, which reduced the availability under the credit facility on a dollar-for-dollar basis. On November 10, 2023, the Company repaid all amounts outstanding under the BCE-Mach Credit Facility and entered into the November 2023 Credit Facility and terminated the BCE-Mach Credit Facility.

BCE-Mach II Credit Facility

On October 25, 2023, the Company assumed the revolving credit facility (the "BCE-Mach II Credit Facility") between BCE-Mach II and a syndicate of banks, including East West Bank, who served as sole book runner and lead arranger. Outstanding obligations under the BCE-Mach II Credit Facility were secured by substantially all of BCE-Mach II's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $250.0 million, subject to a borrowing base of $26.0 million. As of October 25, 2023, $17.1 million was outstanding under the BCE-Mach II Credit Facility. On October 31, 2023, the Company repaid all amounts outstanding under the BCE-Mach II Credit Facility. On November 10, 2023, the Company entered into the November 2023 Credit Facility and terminated the BCE-Mach II Credit Facility.

November 2023 Credit Facility

On November 10, 2023, Holdco, a subsidiary of the Company, entered into the November 2023 Credit Facility with a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger. Outstanding obligations under the November 2023 Credit Facility were secured by substantially all of Holdco's assets, comprising the assets of the Mach Companies. In connection with entering into the November 2023 Credit Facility, each of the Pre-IPO Credit Facilities were terminated.

The aggregate principal amount of loans outstanding under the November 2023 Credit Facility as of November 10, 2023 was $125.0 million, in addition to $5.0 million of issued letters of credit. The November 2023 Credit Facility provided for a revolving credit facility in an aggregate maximum amount of $1.0 billion, with an initial borrowing base of $600.0 million, subject to commitments of $200.0 million. On December 28, 2023, the Company entered into the Credit Agreements and terminated the November 2023 Credit Facility. The termination of the November 2023 Credit Facility was treated as a debt modification, due to the makeup of banks in each credit facility syndicate. The Company wrote off the issuance costs associated with banks exiting the credit facility, and evaluated the decrease in borrowing capacity with remaining syndicate members to write off the proportional amount of issuance costs in comparison to the reduction in borrowing capacity. Total write offs of issuance costs were $1.5 million, and were included in the Company's interest expense on the statement of operations.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 8 for additional information regarding fair value measurements.

The following table summarizes our open financial derivative positions as of December 31, 2023, related to oil production:

Period	Volume (Mbbl)	Weighted Average Fixed Price
Q1 2024	1,094	$ 78.92
Q2 2024	1,083	74.10
Q3 2024	712	72.64
Q4 2024	658	73.16
Q1 2025	307	71.80
Q2 2025	289	71.80
Q3 2025	274	71.80
Q4 2025	260	71.80

The following table summarizes our open financial derivative positions as of December 31, 2023, related to natural gas production:

Period	Volume (Bbtu)	Weighted Average Fixed Price
Q1 2024	2,393	$ 3.10
Q2 2024	2,248	2.94
Q3 2024	10,653	2.96
Q4 2024	10,158	3.73
Q1 2025	4,860	4.34
Q2 2025	4,680	3.69
Q3 2025	4,510	3.92
Q4 2025	4,360	4.36

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following tables presents the gross amounts of recognized derivative assets, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	As of December 31,	
	2023	2022
Derivative contracts – current, gross	$ 24,802	$ —
Netting arrangements	—	—
Derivative contracts – current, net	$ 24,802	$ —
Derivative contracts – long-term, gross	$ 15,112	$ —
Netting arrangements	—	—
Derivative contracts – long-term, net	$ 15,112	$ —

The following tables presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	As of December 31,	
	2023	2022
Derivative contracts – current, gross	$ —	$ 10,080
Netting arrangements	—	—
Derivative contracts – current, net	$ —	$ 10,080

Gains and Losses. The following table presents the settlement and mark-to-market ("MTM") gains and losses on oil and natural gas derivatives presented as a gain or loss on derivatives in the statement of operations for the years ended December 31, 2023, 2022 and 2021 (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Settlements of oil derivatives	$ (5,750)	$ (50,352)	$ (51,832)
Settlements of natural gas derivatives	14,196	(40,436)	(9,432)
MTM gains (losses) on oil derivatives, net	27,559	17,771	(2,753)
MTM gains (losses) on natural gas derivatives, net	21,267	5,564	(3,532)
Total gains (losses) on derivative contracts	$ 57,272	$ (67,453)	$ (67,549)

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2023 and 2022 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of December 31, 2023				
Assets:				
Commodity derivative instruments	$ —	$ 39,914	$ —	$ 39,914
As of December 31, 2022				
Liabilities:				
Commodity derivative instruments	$ —	$ 10,080	$ —	$ 10,080

Fair Value on a Non-Recurring Basis

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Business combinations

Proved properties acquired as a result of business combinations were valued using an income approach based on underlying reserves projections as of the acquisition date. The income approach is considered a Level 3 fair value estimate and includes significant assumptions of future production, commodity prices, operating and capital cost estimates, the weighted average cost of capital for industry peers, which represents the discount factor, and risk adjustment factors based on reserve category. Price assumptions were based on observable market pricing, adjusted for historical differentials, while cost estimates were based on current observable costs inflated based on historical and expected future inflation.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair value due to the short-term maturities of these instruments.

The carrying amount of the Company's Credit Agreements approximate fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation Plans

Equity-based compensation includes unit-based payment awards that are issued to employees and non-employees in exchange for services provided to the Company. Equity-classified unit-based payment awards are recognized at fair value on the grant date and amortized over the requisite service period. For awards with service-based vesting conditions only, the Company recognizes compensation cost using straight-line attribution. The Company uses accelerated attribution for awards that contain market or performance-based vesting conditions. The Company recognizes forfeitures as they occur. Equity-based compensation is presented within general and administrative expense on our consolidated statements of operations.

Post-Offering Grants

On October 27, 2023, the Company adopted a new long-term incentive plan for employees, consultants and directors in connection with the Offering and issued approximately 710,137 phantom units to certain employees of Mach Resources LLC ("Mach Resources") and directors of the Company as compensation for services to be rendered to the Company. The phantom unit awards for all employees of Mach Resources vest ratably on the first three anniversaries of the date of the grant, subject to the employee's continued employment. Within 60 days of the vesting of a phantom unit, the employee will receive a common unit of the Company. Each phantom unit was granted with a corresponding distribution equivalent right, which entitles the participant to receive a payment equal to the total distributions paid by the Company to its common unitholders during the time the phantom unit is outstanding. Payment of the distribution equivalent right occurs when the phantom units vest, and in the event of forfeited units, the corresponding distribution right is also forfeited.

	Phantom Units		Weighted Average Grant Date Fair Value
Granted on October 27, 2023	710,137	$	18.80
Vested	—		—
Forfeited	(592)	$	18.80
Unvested at December 31, 2023	709,545	$	18.80

Total non-cash compensation cost related to the phantom units was $0.8 million for the year ended December 31, 2023. As of December 31, 2023, there was $12.5 million of unrecognized compensation cost related to phantom units that is expected to be recognized over a weighted average period of approximately 2.8 years.

Predecessor Grants

As part of the Predecessor's amended and restated LLC agreement as of March 25, 2021, incentive units (Class B Units) and Class A-2 Units were issued to certain employees of Mach Resources as compensation for services to be rendered to the Predecessor. In determining the appropriate accounting treatment, the Predecessor considered the characteristics of the awards in terms of treatment as stock-based compensation.

The incentive units were subject to graded vesting over a period of approximately 3 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units would forfeit unvested incentive units upon ceasing to be an employee of Mach Resources, excluding limited exceptions. Holders of incentive units were able to participate in distributions upon the Predecessor meeting a certain requisite financial internal rate of return threshold as defined in the Predecessor's amended LLC agreement.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For Predecessor awards granted during the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Predecessor's business of 53%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

A summary of the Predecessor's incentive unit awards as of December 31, 2023 is as follows:

	Predecessor Class B Units		Weighted Average Grant Date Fair Value
Granted on March 25, 2021	20,000	$	2,378.80
Vested	(9,667)		2,378.80
Unvested at December 31, 2021	10,333		2,378.80
Vested	(3,665)		2,378.80
Unvested at December 31, 2022	6,668		2,378.80
Vested	(6,668)	$	2,378.80
Unvested at December 31, 2023	—		N/A

On October 25, 2023, all unvested Class B Units immediately vested and were exchanged for common units in the Company as part of the Corporate Reorganization. Total consideration transferred in the exchange of Class B Units for common units was $302.7 million. All unrecognized compensation costs were expensed upon the vesting of the Class B Units. Total non-cash compensation cost related to the incentive units was $2.6 million, $7.5 million and $37.4 million for the years ended December 31, 2023, 2022 and 2021, respectively. As of December 31, 2023, there was no unrecognized compensation cost related to incentive units.

On March 25, 2021, the Predecessor issued 1,349 Class A-2 Units, and additional A-2 Units were issued on a quarterly basis to the employee for the year ended December 31, 2021 that vested on the grant date. In 2022, the Class A-2 Issuance Agreement was updated and there were no additional units granted to the employee.

There were no unvested Class A-2 Units and no unrecognized compensation costs as of December 31, 2023. There was no non-cash compensation cost related to the Class A-2 Units for the years ended December 31, 2023 and 2022. Non-cash compensation cost related to the Class A-2 Units was $7.8 million for the year ended December 31, 2021.

10. Commitments and Contingencies

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of December 31, 2023 and 2022. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

NGL Sales and Gas Transportation Commitments

The Company is party to a NGL sales contract, which includes certain NGL volume commitments in the event the Company elects not to reduce its committed quantity, at its option. To the extent the Company does not deliver NGL volumes in sufficient quantities to meet the commitment and does not elect to reduce its committed quantity, it would be required to pay a deficiency fee. The Company is currently delivering at least the minimum volumes. Additionally, the Company has natural gas firm transportation agreements terminating in 2024. For the years ended December 31, 2023, 2022, and 2021, the Company incurred approximately $1.0 million, $0.4 million and $0.3 million, respectively, of transportation charges under these agreements. Total remaining payments under these contracts were approximately $7.0 million as of December 31, 2023.

Contributions to 401(k) Plan

The Company 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 provides a company match on 100% of salary deferrals that do not exceed 10% of compensation. We contributed $1.7 million, $1.0 million, and $0.7 million for the years ended December 31, 2023, 2022 and 2021, respectively.

11. Leases

Effective January 1, 2022, the Company adopted ASU No. 2016-02, Leases (Topic 842). The new standard superseded the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases.

Nature of Leases

The Company has operating leases on various vehicles and compressors with remaining lease durations in excess of one year. These leases have various expiration dates through 2027. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability 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.

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 the 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, 2023, were as follows (in thousands):

2024	$ 11,325
2025	4,796
2026	1,586
2027	604
Total lease payments	18,311
Less: imputed interest	(841)
Total	$ 17,470

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the years ended December 31, 2023 and 2022 (in thousands):

	Year ended December 31,	
	2023	2022
Operating lease cost	$ 14,309	$ 7,462
Short-term lease cost	11,579	9,300
Total lease cost	$ 25,888	$ 16,762

The weighted-average remaining lease term as of December 31, 2023 was1.87 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2023 was 5.07%.

	Year ended December 31,	
	2023	2022
Operating cash flows from operating leases	$ 14,066	$ 6,707

12. Partners' Capital and Members' Equity

Partners' Capital

The Company was formed to effectuate the Corporate Reorganization, the Offering and related transactions thereto, as described inNote 1. Nature of Business. On October 25, 2023, the Company issued 88,750,000 common units to Existing Owners of the Mach Companies. SeeNote 3 for additional information on the merger transactions related to the acquisitions of BCE-Mach and BCE-Mach II. On October 27, 2023, the Company completed the Offering and issued 10,000,000 common units to public unitholders. Contemporaneously, the Company used a portion of the proceeds from the

Offering to repurchase 3,750,000 common units from certain Existing Owners of the Mach Companies. As of December 31, 2023, the Company had 95,000,000 common units outstanding.

Members' Equity

Members' equity of the Predecessor initially consisted of a single class of common interests, that were all owned by BCE-Mach Intermediate Holdings III LLC. On March 25, 2021, per the Predecessor's amended and restated LLC agreement and the Class A-2 Issuance Agreement, the Predecessor issued 150,000 Class A-1 Units to its initial member, and 1,349 Class A-2 Units to an employee of Mach Resources for services performed for the Predecessor. Additional Class A-2 Units were granted to the employee on a quarterly basis throughout 2021 for a total of 3,504 Class A-2 Units granted, which have substantially all the same rights as the initial member. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were issued and outstanding as of December 31, 2022. The Class B Units represented a non-voting interest in the Company that allowed the holder to participate in distributions once the Predecessor's Class A units met a certain requisite financial internal rate of return in accordance with the Predecessor's LLC agreement. See Note 9 for additional information on equity grants by the Predecessor. All of the equity interests in the Predecessor were exchanged for common units of the Company as part of the Corporate Reorganization.

Contributions from the Company's predecessor members were $20.0 million, $65.0 million and $101.5 million for the years ended December 31, 2023, 2022 and 2021, respectively. Distributions to the Company's predecessor members were $101.4 million, $274.8 million and $146.0 million for the years ended December 31, 2023, 2022 and 2021, respectively.

13. Earnings Per Common Unit

The Company has a single class of common units representing limited partnership interests. The Company has potentially dilutive securities as of December 31, 2023, which consist of phantom units issued under the Company's long-term incentive plan. As of December 31, 2023, all 709,545 phantom units were excluded from the calculation of earnings per unit because the units were considered anti-dilutive.

The following represents the computation of basic and diluted earnings per common unit for the year ended December 31, 2023 (in thousands, except per unit data):

	Year Ended December 31, 2023
Net income attributable to Mach Natural Resources LP	$ 68,518
Weighted-average common units outstanding	94,907
Earnings per common unit - basic and diluted	$ 0.72

14. Related Party Transactions

Management Services Agreement. Upon formation of the Predecessor, the Predecessor entered into a management services agreement (the "Predecessor MSA") with Mach Resources. On October 27, 2023, in connection with the closing of the Offering, the Company entered into a new management services agreement (the "MSA," and together with the Predecessor MSA, the "MSAs") with Mach Resources and terminated the Predecessor MSA. Under the MSAs, Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company and (i) will pay Mach Resources an annual management fee of approximately $7.4 million and (ii) reimburse Mach Resources for the costs and expenses of the Services provided. On a monthly basis, the Company distributes funding to Mach Resources for performance under the MSAs. During the years ended December 31, 2023, 2022 and 2021, the Company paid Mach Resources $52.3 million (inclusive of $4.8 million in management fees presented in general and administrative expense in the statement of operations), $33.7 million (inclusive of $2.0 million in management fees presented in general and administrative expense in the statement of operations) and $23.6 million (including no management fees), respectively. As of December 31, 2023 and 2022, the Company owed $2.9 million and $0.4 million, respectively, to Mach Resources, presented in accounts payable.

BCE-Stack Development LLC. BCE-Stack Development LLC ("BCE-Stack") is an affiliate of the member, and previously was an owner of working and revenue interests in a subset of the Company's wells. BCE-Stack sold their interests in the wells to the Company on February 28, 2022. See Note 3 for additional information on the acquisition. As of December 31, 2023 and 2022, the Company had no receivables or payables with BCE-Stack.

BCE-Mach and BCE-Mach II. BCE-Mach and BCE-Mach II were two related parties that previously entered into a MSA with Mach Resources. These entities had shared ownership, but were not under common control, with the Company prior to the Corporate Reorganization on October 25, 2023. See Note 1 and Note 3 for further discussion of the transactions involving these entities. As of December 31, 2023 and for periods subsequent to the Corporate Reorganization, all account balances and activities between the Company and these entities have been eliminated as intercompany transactions. As of December 31, 2022, the Company had receivables from these related parties for approximately $0.7 million included in accounts receivable — joint interest and other.

15. Subsequent Events

On February 15, 2024, the Company declared its quarterly distribution for the fourth quarter of 2023 of $0.95 per common unit, which was paid on March 14, 2024.

Subsequent to December 31, 2023 the Company entered into the following derivative contracts:

Period	Volume	Weighted Average Fixed Price
Oil	**Mbbl**	
Q2 2024	16	$ 78.01
Q3 2024	7	$ 76.25
Q4 2024	2	$ 74.56
Q1 2025	306	$ 72.91
Q1 2026	245	$ 68.70

The Company has evaluated subsequent events through the date of issuance of these financial statements to ensure that any subsequent events that met the criteria for recognition and disclosure in this Annual Report have been properly included.

16. Supplementary Financial Information for Oil and Gas Producing Activities (*Unaudited*)

The following tables provide historical cost information regarding the Company's oil and gas operations located entirely in the United States:

Capitalized Costs related to Oil and Gas Producing Activities

	As of December 31,	
(in thousands)	**2023**	**2022**
Proved properties	$ 2,097,540	$ 749,934
Accumulated depreciation, depletion, amortization and impairment	(265,895)	(139,514)
Net capitalized costs	$ 1,831,645	$ 610,420

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	Year Ended December 31,		
(in thousands)	**2023**	**2022**	**2021**
Acquisition	$ 774,887	$ 130,866	$ 130,959
Development	290,371	262,889	51,886
Exploratory	—	—	—
Costs incurred	$ 1,065,258	$ 393,755	$ 182,845

MACH NATURAL RESOURCES LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Results of Operations for Producing Activities

The following table includes revenue and expenses related to the production and sale of oil, natural gas, and NGLs. It does not include any derivative activity, interest costs or general and administrative costs.

	Year Ended December 31,		
(in thousands)	**2023**	**2022**	**2021**
Revenues	$ 647,352	$ 860,388	$ 397,500
Production costs	(198,933)	(191,250)	(94,543)
Depreciation, depletion, amortization and accretion	(131,145)	(84,070)	(37,537)
Results of operations from producing activities	$ 317,274	$ 585,068	$ 265,420

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

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

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the US GAAP. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired. See Note 2 for additional information related to asset retirement obligations.

The standardized measure does not represent management's estimate of our future cash flows or the fair value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves Summary

All of the Company's reserves are located in the United States. The following table sets forth the changes in the Company's net proved reserves (including developed and undeveloped reserves) for the years ended December 31, 2023, 2022 and 2021. Reserves estimates as of December 31, 2023 and 2022 were estimated by our independent petroleum consulting firm Cawley, Gillespie & Associates, Inc.

Proved Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2020	14,800	139,745	9,194	47,285
Revisions of previous estimates	18,685	122,349	9,541	48,618
Purchases in place	5,064	207,338	13,500	53,121
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(2,775)	(32,313)	(2,180)	(10,340)
December 31, 2021	35,775	437,120	30,055	138,683
Revisions of previous estimates	15,675	167,606	11,360	54,969
Purchases in place	1,919	72,451	8,230	22,224
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(4,789)	(47,557)	(2,812)	(15,527)
December 31, 2022	48,580	629,620	46,833	200,349
Revisions of previous estimates	(724)	(95,816)	(13,768)	(30,461)
Purchases in place	33,198	632,049	55,668	194,208
Extensions, discoveries and other additions	—	—	—	—
Sales in place	(36)	—	—	(36)
Production	(5,445)	(59,378)	(3,068)	(18,409)
December 31, 2023	75,573	1,106,475	85,665	345,650

Proved Developed Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2021	22,794	415,141	29,736	121,719
December 31, 2022	29,984	527,369	39,239	157,117
December 31, 2023	49,629	909,372	69,193	270,384

Proved Undeveloped Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2021	12,981	21,979	319	16,964
December 31, 2022	18,596	102,251	7,594	43,232
December 31, 2023	25,944	197,103	16,472	75,266

In 2021, the 53,121 MBoe acquisitions represents the reserves acquired from several acquisitions that closed in 2021. See Note 3 for more information. The 48,618 MBoe of upward revisions in proved reserves were the result of a combination of higher commodity prices (20,900 MBoe), positive changes to production forecasts (4,600 MBoe), adjustments to product pricing differentials and lease operating expenses (5,900 MBoe) and the addition of PUDs based on drilling results (17,000 MBoe).

In 2022, the 22,224 MBoe of acquisitions represents the reserves acquired from several acquisitions that closed in 2022. See Note 3 for more information. The 54,969 MBoe of upward revisions in proved reserves were the result of higher commodity prices (9,000 MBoe), the addition of PUDs (35,800 MBoe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (7,200 MBoe). The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

In 2023, the 194,208 MBoe of acquisitions represents the reserves acquired from several acquisitions that closed in 2023. See Note 3 for more information. The 30,461 MBoe of downward revisions in proved reserves were the result of lower commodity prices (-20,408 MBoe), the addition of PUDs within proven areas of development (23,014 MBoe), the deletion of PUDs due to changes in the corporate development plan (-36,762 MBoe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (8,672 MBoe). The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

The following table sets forth the standardized measure of discounted future net cash flow from projected production of the Company's oil and natural gas reserves:

Standardized Measure of Discounted Future Net Cash Flows (in thousands)	**As of December 31, 2023**	**2022**	**2021**
Future cash inflows	$ 9,729,149	$ 9,666,636	$ 4,482,198
Future costs:			
Production[(1)]	(3,831,083)	(3,143,467)	(1,670,421)
Development[(2)]	(1,097,667)	(876,115)	(290,564)
Income taxes	—	—	—
Future net cash flows	4,800,399	5,647,054	2,521,213
10% annual discount	(2,223,540)	(2,693,549)	(1,107,602)
Standardized measure	$ 2,576,859	$ 2,953,505	$ 1,413,611

(1) Production costs include production severance taxes, ad valorem taxes and operating expenses.
(2) Development costs include plugging expenses, net of salvage and net capital investment.

Changes in Standardized Measure of Discounted Future Net Cash Flows (in thousands)	**Year Ended December 31, 2023**	**2022**	**2021**
Standardized measure, beginning of period	$ 2,953,505	$ 1,413,611	$ 319,372
Revisions of previous quantity estimates	(509,130)	962,927	574,343
Changes in estimated future development costs	4,361	169,405	89,648
Purchases of minerals in place	1,374,144	201,135	319,488
Net changes in prices and production costs	(1,248,485)	442,599	379,219
Divestiture of reserves	(1,207)	—	—
Accretion of discount	295,351	141,361	31,937
Sales of oil and gas produced, net of production costs	(448,419)	(669,138)	(302,957)
Development costs incurred during the period	56,064	261,650	51,281
Change in timing of estimated future production and other	100,675	29,955	(48,720)
Standardized measure, end of period	$ 2,576,859	$ 2,953,505	$ 1,413,611

Price and cost revisions are primarily the net result of changes in prices, based on beginning of the year reserve estimates. Future development costs revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Average oil prices used in the estimation of proved reserves and calculation of the standardized measure were $78.22, $93.67 and $66.56 for the years ended December 31, 2023, 2022 and 2021, respectively. Average realized gas prices were $2.64, $6.36 and $3.60 for the years ended December 31, 2023, 2022 and 2021, respectively. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(b) under the Exchange Act) as of December 31, 2023. Based on such evaluation, such officers have concluded that, as of December 31, 2023, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined by Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2023, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control over Financial Reporting

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Item 9B. Other Information

Not applicable.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Mach Natural Resources

We are managed and operated by our general partner, which is managed by the Board and executive officers of our general partner. The members of our general partner are BCE-Mach Aggregator, which is controlled by our Sponsor, and Mach Resources, which is controlled by Tom L. Ward. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to us as well as to its owners.

Our general partner has five directors, each of whom have been appointed by the Sponsor and Tom L. Ward through his ownership of Mach Resources, as the member of our general partner. The NYSE does not require a listed publicly traded limited partnership, such as ours, to have a majority of independent directors on the Board or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering.

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, we do not have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by third parties, such as pursuant to the MSA, but we sometimes refer to these individuals, for drafting convenience only, as our employees because they provide services directly to us.

The management, maintenance and operational functions of our business are currently provided by Mach Resources pursuant to the MSA.The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our general partner directly nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. These expenses include salary, benefits, bonus, long term incentives and other amounts paid to persons who perform services for us or on our behalf.

In evaluating director candidates, our general partner assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board’s ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties.

Executive Officers and Directors of Our General Partner

The following table sets forth certain information regarding the current executive officers and directors of our general partner.

Name	Age	Position
Tom L. Ward	64	Chief Executive Officer and Director
Kevin R. White	66	Chief Financial Officer
Daniel T. Reineke, Jr.	41	Executive Vice President, Business Development
Michael E. Reel	38	General Counsel and Secretary
William McMullen	38	Chairman of the Board
Edgar R. Giesinger	67	Director
Stephen Perich	44	Director
Francis A. Keating II	80	Director

Tom L. Ward — Chief Executive Officer and Director. Mr. Ward has served as our Chief Executive Officer since our founding in 2017 and as a Director since the Offering. Prior to joining the Company, he served as Chairman and Chief Executive Officer of Tapstone Energy from 2013 to 2017 and Sandridge Energy (NYSE: SD) from 2006 to 2013. Prior to joining SandRidge Energy, he served as President, Chief Operating Officer and a director of Chesapeake Energy

Corporation (NYSE: CHK) from the time he co-founded the company in 1989 until February 2006. Mr. Ward graduated from the University of Oklahoma in 1981 with a Bachelor of Business Administration in Petroleum Land Management.

We believe that Mr. Ward's extensive industry background, his previous experience as a director and executive of public companies, and deep knowledge of our business as founder make him well suited to serve as a member of our board of directors.

Kevin R. White — Chief Financial Officer. Mr. White has served as our Chief Financial Officer since March 2017. Prior to joining the Company, he served as Chief Financial Officer of Petroflow Energy Corporation from June 2016 to March 2017 and as SVP — Business Development and Investor Relations of SandRidge Energy from January 2008 to September 2013. Mr. White served as Executive Vice President of Corporate Development and Strategic Planning for Louis Dreyfus Natural Gas Corp. from 1993 until the company was sold in 2001. He attended Oklahoma State University, receiving his Bachelor of Science degree in Accounting in 1979 and a Master of Science degree in Accounting and his Certified Public Accountant qualification in 1980.

Daniel T. Reineke, Jr. — Executive Vice President, Business Development. Mr. Reineke has served as Executive Vice President, Business Development since our founding in 2017. Prior to joining the Company, he served as Chief Investment Officer for TLW Trading since 2013. Prior to his time with TLW Trading, Mr. Reineke served as a Vice President at RBC Wealth Management, Vice President/General Counsel for Stampede Farms, and Associate General Counsel at Gulfport Energy Corporation (NYSE: GPOR). Mr. Reineke graduated from the University of Oklahoma School of Law receiving his Juris Doctorate in 2007 after receiving his Bachelor of Business Administration in Finance in 2004 from the University of Oklahoma.

Michael E. Reel — General Counsel and Secretary. Mr. Reel joined the Company in July 2017 and currently serves as General Counsel and Secretary. Prior to joining the Company, he served as Senior Counsel for Accelerate Resources. Prior to his time at Accelerate Resources, Mr. Reel served as internal counsel for White Star Petroleum, LLC, American Energy Partners, LP and Chesapeake Energy Corporation. Mr. Reel graduated from Oklahoma State University in 2008 with a Bachelor of Science degree in Political Science and received his Juris Doctorate from Oklahoma City University School of Law in 2011.

William W. McMullen — Chairman of the Board. Mr. McMullen has served as Chairman of the Board since the Offering, and as Founder and Managing Partner of BCE since 2015, leading the firm's investment strategy and capital allocation decisions. Prior to founding BCE in 2015, Mr. McMullen worked at White Deer Energy from 2012 to 2014. Previously, Mr. McMullen worked at Denham Capital Management from 2010 to 2012 and UBS Investment Bank's Global Energy Group from 2008 to 2010. Mr. McMullen earned his AB in Economics, with Honors, from Harvard University.

We believe that Mr. McMullen's industry experience, his previous leadership positions and finance-related roles, as well as his deep knowledge of our business, make him well suited to serve as a member of our board of directors.

Edgar R. Giesinger — Director. Mr. Giesinger has served as a Director since the Offering. Mr. Giesinger retired as a managing partner from KPMG LLP in 2015. Since November 2015, Mr. Giesinger has served on the board of directors of Geospace Technologies Corporation (NASDAQ: GEOS), a publicly traded company primarily involved in the design and manufacture of instruments and equipment utilized in oil and gas industries. Mr. Giesinger has served on the board of directors of Solaris Oilfield Infrastructure, Inc. (NYSE: SOI), a public company involved in providing proppant management systems for oil and gas well sites, since May 2017. Mr. Giesinger served on the board of directors of Newfield Exploration Company, a publicly traded crude oil and natural gas exploration and production company, from August 2017 until February 2019 when it was sold to Encana Corporation. He has 35 years of accounting and finance experience working mainly with publicly traded corporations. Over the years, he has advised a number of clients in accounting and financial matters, capital raising, international expansions and in dealings with the SEC. While working with companies in a variety of industries, his primary focus has been energy and manufacturing clients. Mr. Giesinger is a certified public accountant in the State of Texas and former chairman of the Texas TriCities Chapter of the National Association of Corporate Directors. He has lectured and led seminars on various topics dealing with financial risks, controls and financial reporting. Mr. Giesinger graduated from the University of Texas with a Bachelor of Business Administration in Accounting.

We believe that Mr. Giesinger's extensive financial and accounting experience, including that related to the energy and manufacturing industries, qualifies him to effectively serve as a member of the Board.

Stephen Perich — Director. Mr. Perich has served as a Director since the Offering. Mr. Perich served as the Head of Energy Investment Banking for the Americas at UBS Investment Bank from August 2018 to November 2023. As head of

UBS' energy investment banking practice, he has been a manager of a team of professionals focused on capital markets execution and mergers and acquisitions advisory services. He maintains regular strategic dialogue with management teams and boards of directors of energy companies, assisting them with capital raising and strategic growth initiatives. Since January 2024, he has served on the Board of Directors of Visuray PLC, a private technology company. He has lectured and led conferences on various topics including energy fundamentals and capital markets. Mr. Perich graduated from Georgetown University in 2001 with a Bachelor of Science degree in Finance and received a Master of Business Administration from the University of Texas at Austin in 2006.

We believe that Mr. Perich's extensive experience in financial markets, oil and gas, capital markets and mergers and acquisitions, including that related to the energy and manufacturing industries, qualifies him to effectively serve as a member of the Board.

Francis A. Keating II — Director. Governor Keating has served as a Director since the Offering. Governor Keating is the former Governor of the State of Oklahoma, a position in which he served from 1995 to 2003. More recently, he has served on The University of Oklahoma Board of Regents since 2017, elected to serve as Chairman in 2022. Mr. Keating has served on the board of directors of Citizens Inc. (NYSE: CIA) since 2017 and on the board of directors of BancFirst Corporation (Nasdaq: BANFP) since 2016. Previously, he was a partner at the law firm of Holland & Knight from February 2016 to December 2018. He served as President and Chief Executive Officer of the American Bankers Association from 2011 to 2016, and President and Chief Executive Officer of the American Council of Life Insurers, the trade association for the life insurance and retirement security industry, from 2003 to 2011.

Mr. Keating has held significant leadership positions in both the public and private sectors, which make him a valuable addition to our Board. In addition to serving as the Governor of Oklahoma, his impressive career included serving as assistant secretary of the Treasury and associate attorney general under President Ronald Reagan. He was later general counsel and acting deputy secretary for the Department of Housing and Urban Development ("HUD") under President George H.W. Bush. During his tenure at the Treasury Department and HUD, he worked on significant issues affecting insurance, banking, and the financial services industries. In addition to his current public board, Gov. Keating formerly served on the board of Stewart Title Company, a wholly-owned subsidiary of Stewart Information Services Corp., a publicly held title insurance and real estate services company, from 2006 to January 2017, where he chaired the Nominations and Corporate Governance Committee. Mr. Keating graduated from Georgetown University with a Bachelor of Arts in History and received his Juris Doctorate from University of Oklahoma School of Law.

We believe that Mr. Keating's impressive legal and public service career further strengthens our Board's governance and oversight function and qualifies him to effectively serve as a member of the Board.

Board of Directors

Our general partner has a five-member board of directors. The members of our general partner are (i) BCE-Mach Aggregator, the majority of the membership interests of which are owned by investment funds managed by Bayou City Energy Management LLC and its affiliates, and (ii) Mach Resources, which is controlled by Tom L. Ward, with such membership interests and Board appointment rights of such members held in proportion to their respective limited partnership interest ownership in us. Such proportional membership interest of Tom L. Ward includes certain ownership of trusts affiliated with Mr. Ward, which such membership interests currently represent approximately 1.7% of our outstanding common units. Specifically, each of BCE-Mach Aggregator and Mach Resources shall separately be entitled to appoint (i) one director if its membership interests are greater than 0% but equal to or less than 25%, (ii) two directors if its membership interests are greater than 25% but equal to or less than 50%, (iii) three directors if its membership interests are greater than 50% but equal to or less than 75%, (iv) four directors if its membership interests are greater than 75% but less than 100% and (v) five directors if its membership interests are 100%. Further, to the extent each of BCE-Mach Aggregator and Mach Resources are entitled to appoint a director, each shall only be entitled to appoint one director that is not Independent (as defined in the general partner agreement). As a result, the Sponsor controls our general partner and is entitled to appoint four members of the Board and Mach Resources is entitled to appoint one member of the Board.

In evaluating director candidates, sole members of our general partner assessed whether a candidate possessed the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the Board to fulfill their duties.

Our general partner's directors hold office until the earlier of their death, resignation, retirement, disqualification or removal or until their successors have been duly elected and qualified.

Additionally, pursuant to the general partner agreement, the Board has the right by delivery of written notice to BCE-Mach Aggregator and Mach Resources to require the Company, the Board and BCE-Mach Aggregator and Mach Resources, to take all necessary action to transfer all of the outstanding membership interests of our general partner to the Company for no additional consideration and amend our partnership agreement to provide the holders of common units with voting rights in the election of the members of the Board, as the general partner of the Company.

Director Independence

Our independent directors meet the independence standards established by the NYSE listing rules.

Code of Business Conduct and Ethics

Our Board of Directors has adopted a Code of Ethics, which is available free of charge on our website, ir.machnr.com. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Ethics by posting such information on the website address and location specified above.

Committees of the Board of Directors

The Board has an audit committee, a compensation committee, and a conflicts committee. The NYSE listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. However, we have established a compensation committee that has the responsibilities set forth below.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE listing rules and rules of the SEC. The audit committee assists the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management. Edgar R. Giesinger, Stephen Perich and Francis A. Keating II serve on the audit committee. Edgar R. Giesinger serves as chair of the audit committee. SEC rules also require that a public company disclose whether its audit committee has an “audit committee financial expert” as a member. The Board has determined that Edgar R. Giesinger qualifies as an “audit committee financial expert,” as such term is defined in Item 407(d) of Regulation S-K.

Conflicts Committee

In accordance with the terms of our partnership agreement, two or more members of the Board serve on our conflicts committee to review specific matters that may involve conflicts of interest. The members of our conflicts committee cannot be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on a conflicts committee of a board of directors. In addition, the members of our conflicts committee cannot own any interest in our general partner or its affiliates or any interest in us or our subsidiaries other than common units or awards, if any, under our incentive compensation plan. Edgar R. Giesinger, Stephen Perich and Francis A. Keating II serve as members of our conflicts committee.

Compensation Committee

The members of our compensation committee are Edgar R. Giesinger, Stephen Perich and William McMullen. Stephen Perich serves as chair of the compensation committee. Each of the members of our compensation committee are independent under the applicable rules and regulations of the NYSE and are a “non-employee director” as defined in Rule 16b-3 promulgated under the Exchange Act. The compensation committee operates under a written charter that satisfies the applicable standards of the SEC and the NYSE.

The compensation committee’s responsibilities include:

- annually reviewing and approving corporate goals and objectives relevant to compensation of our chief executive officer and our other executive officers;

- annually reviewing and making recommendations to our board of directors with respect to the compensation of our chief executive officer and determining the compensation for our other executive officers;
- reviewing and making recommendations to our board of directors with respect to director compensation; and
- overseeing and administering our equity incentive plans.

From time to time, our compensation committee may use outside compensation consultants to assist it in analyzing our compensation programs and in determining appropriate levels of compensation and benefits. The compensation committee will review and evaluate, at least annually, the performance of the compensation committee and its members, including compliance by the compensation committee with its charter.

Board Leadership Structure

Leadership of our general partner's board of directors is vested in a Chairman of the Board. Mr. William McMullen serves as a Director and the Chairman of the Board. We have no policy with respect to the separation of the offices of chairman of the Board and chief executive officer. Instead, that relationship is defined and governed by the general partner agreement of our general partner, which permits the same person to hold both offices. Directors of the Board are designated or elected by the Sponsor and Tom L. Ward through his ownership of Mach Resources as the members of our general partner. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines provide that the Board is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our independent registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

Delinquent Section 16(a) Reports

None.

Item 11. Executive Compensation

We do not directly employ directors, officers or employees; instead, all of the employees that conduct our business are either employed by Mach Resources or its subsidiaries. We depend on Mach Resources and such employees to provide us and our General Partner with services necessary to operate our business. The management, maintenance and operational functions of our business are currently provided by Mach Resources pursuant to the MSA. The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our general partner nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us. The reimbursement of expenses to our General Partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. During the year ended December 31, 2023, we paid $52.3 million to Mach Resources, which consists of $4.8 million for an annual management fee and $47.5 million for reimbursements of its costs and expenses under the Predecessor MSA and the MSAs in effect between Mach Resources, on the one hand, and each of BCE-Mach and BCE-Mach II, on the other hand, prior to the Offering.

For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report. Although all of the employees that conduct our business are employed by Mach Resources, we sometimes refer to these individuals in this Annual Report as our employees.

Emerging Growth Company Status

We are currently considered an "emerging growth company," within the meaning of the Securities Act, for purposes of the SEC's executive compensation disclosure rules. Accordingly, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures regarding executive compensation for our last completed fiscal year. Furthermore, our reporting obligations extend only to our "named executive officers," who are the individuals who served as our principal executive officer during 2023 and our next two most highly compensated executive officers at the end of 2023. Accordingly, our "Named Executive Officers" for 2023 are:

Name	Principal Position
Tom L. Ward	Chief Executive Officer
Kevin R. White	Chief Financial Officer
Daniel T. Reineke, Jr.	Executive Vice President — Business Development

2023 Summary Compensation Table

The following table summarizes the compensation awarded to, earned by or paid to our Named Executive Officers for the fiscal year ended December 31, 2023.

Name and Principal Position	Year	Salary[1]	Bonus[2]	Stock Awards[3]	Non-Equity Incentive Plan Compensation[4]	All Other Compensation[5]	Total
Tom L. Ward	2023	$ 600,000	$ —	$ 2,077,889	$ 4,056,656	$ 329,304	$ 7,063,849
Chief Executive Officer	2022	$ 600,000	$ —	$ —	$ —	$ 337,396	$ 937,396
Kevin R. White	2023	$ 546,250	$ 81,937	$ 1,292,594	$ 205,086	$ 30,000	$ 2,155,867
Chief Financial Officer	2022	$ 475,000	$ 47,500	$ —	$ —	$ 27,000	$ 549,500
Daniel T. Reineke, Jr.	2023	$ 760,100	$ 114,016	$ 1,292,594	$ 205,086	$ 22,500	$ 2,394,296
Executive Vice President — Business Development	2022	$ 660,960	$ 66,096	$ —	$ —	$ 20,500	$ 747,556

(1) The amounts in this column reflect the base salary earned by each Named Executive Officer in each of the 2023 and 2022 fiscal years.

(2) The amounts in this column represent discretionary short-term cash incentive awards paid for each of the 2023 and 2022 fiscal years. Bonus amounts were determined as more specifically discussed under "Narrative Disclosure to Summary Compensation Table — Annual Bonuses."

(3) The amounts reported in this column represent the grant date fair value of Award Units (as defined below) granted to our Named Executive Officers pursuant to the Long-Term Incentive Plan (as defined below) on October 27, 2023. The amounts shown in this column were computed in accordance with Financial Accounting Standards Board ("FASB") Accounting Standard Codification ("ASC") Topic 718. See Note 9 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report for details. These amounts do not necessarily correspond to the actual value that will be realized by our Named Executive Officers.

(4) In connection with the consummation of the Offering, each of our Named Executive Officers holding Class B Units of BCE-Mach III at such time received a bonus payment calculated based on the aggregate cumulative amounts distributed to the holders of Class B Units of BCE-Mach III under the operating agreement of BCE-Mach III as of such Change of Control.

(5) The amounts in this column reflect the Company's matching contributions to the Company's 401(k) plan for the Named Executive Officers for each of the 2023 and 2022 fiscal years. For Mr. Ward, these amounts include personal use of chartered aircraft of $0.3 million for fiscal years ended December 31, 2023 and 2022.

Narrative Disclosure to Summary Compensation Table

No Employment Agreements and/or Offer Letters

We have not entered into any employment agreement, offer letter or similar employment contract with any of our Named Executive Officers.

Base Salary

Each Named Executive Officer's base salary is a fixed component of compensation for performing specific job duties and functions. Base salaries are generally set at levels deemed necessary to attract and retain individuals with superior talent commensurate with their relative expertise and experience. Mr. White received a base salary increase from $475,000 to $546,250 on January 1, 2023, and Mr. Reineke received a base salary increase from $660,960 to $760,100 on January 1, 2023.

Annual Bonuses

Annual cash bonuses are used to motivate and reward our executives and other employees. The annual bonuses paid to our Named Executive Officers (other than Mr. Ward) for the 2023 and 2022 fiscal years were discretionary bonuses ultimately determined by Mr. Ward and not linked to any performance metrics of the Company or otherwise. Mr. Ward historically has not been considered for annual bonuses and, accordingly, Mr. Ward did not receive an annual bonus in 2023 or 2022. The target annual bonus opportunity for each of Messrs. White and Reineke is not memorialized in any written plan or other document but has historically been approximately 10% of their base salaries. For 2023, the payments of annual bonuses for Messrs. White and Reineke were divided into two installments, with half of the bonuses becoming payable in July 2023 and the remaining half becoming payable in January 2024.

Equity Incentives

Class B Units in the Mach Companies

In connection with the formation of each of the Mach Companies, each of our Named Executive Officers received one-time awards of Class B Units in each of the Mach Companies. The Mach Companies Class B Units were equity incentive awards intended to qualify as “profits interests” for U.S. federal income tax purposes and were subject to service-based vesting over a period of 3 years for Mr. Ward and 2 years for Messrs. White and Reineke. Under the applicable equity agreements between each of the Named Executive Officers and the Mach Companies, if a Named Executive Officer’s employment was terminated due to his death or disability, then the next tranche of unvested Mach Companies Class B Units, as applicable, held by the Named Executive Officer scheduled to vest on the next vesting date following the termination date would immediately vest as of the termination date. In addition, each Named Executive Officer’s unvested Mach Companies Class B Units would become fully vested immediately prior to a “Change of Control” (as defined in the applicable operating agreement of the Mach Companies and including an initial public offering), subject to the Named Executive Officer’s continued employment through the Change of Control. In connection with the Corporate Reorganization, the Mach Companies Class B Units became fully vested and exchanged for their respective pro rata portions of the common units of the Company, after which the Mach Companies Class B Units were cancelled and ceased to exist. See notes 9 and 12 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report.

2023 Long-Term Incentive Plan

In connection with the consummation of the Offering, the Board adopted a long-term incentive plan (the “Long-Term Incentive Plan”) in which our Named Executive Officer, employees, consultants and directors are eligible to participate. The Long-Term Incentive Plan provides for the grant of cash awards, options to purchase common units of the Company, unit appreciation rights, restricted units, phantom units (“Award Units”), unit awards, distribution equivalent rights (“DERs”) and other unit-based awards intended to align the interests of service providers, including our Named Executive Officers, with those of our unitholders. The Long-Term Incentive Plan is filed herewith as Exhibit 10.1.

In connection with the consummation of the Offering, we granted awards under the Long-Term Incentive Plan. The awards granted to our Named Executive Officers were comprised of Award Units, each of which was issued in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding. The Award Units vest ratably on each of the first three anniversaries of the date of grant, subject to the Named Executive Officer’s continued employment through the applicable vesting date, and an Award Unit’s corresponding DER vests at the same time the Award Unit vests. The Award Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting as discussed under “Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control.”

Outstanding Equity Awards at 2023 Fiscal Year-End

The following table sets forth information regarding all outstanding equity incentive awards held by each of our Named Executive Officers as of December 31, 2023.

Name	Grant Date	Number of Units That Have Not Vested[1]	Market Value of Units That Have Not Vested[2]
Tom L. Ward	10/27/2023	110,526	$ 1,822,574
Kevin R. White	10/27/2023	68,755	$ 1,133,770
Daniel T. Reineke, Jr.	10/27/2023	68,755	$ 1,133,770

(1) Represents Award Units that will vest one-third on October 27 of each of 2024, 2025 and 2026, subject to the Named Executive Officer's continued employment through each applicable vesting date. Each Award Unit was granted in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding. An Award Unit's corresponding DER vests at the same time the Award Unit vests. The Award Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting as discussed under "Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control."

(2) The amounts in this column were calculated based on $16.49, the closing price of our common units on the New York Stock Exchange on December 29, 2023, the last trading day in fiscal year 2023.

Additional Narrative Disclosure

Retirement Benefits

We do not have a defined benefit pension plan or nonqualified deferred compensation plan. We currently maintain a retirement plan intended to provide benefits under Section 401(k) of the Code, pursuant to which employees, including the Named Executive Officers, can make voluntary pre-tax contributions. We match 100% of elective deferrals up to 10% of salary for our Named Executive Officers. Our employer matching contributions vest in equal, annual installments on the first four anniversaries of a participant's commencement of service, and our Named Executive Officers are 100% vested in employer matching contributions. All contributions under the retirement plan are subject to certain annual dollar limitations, which are periodically adjusted for changes in the cost of living.

Potential Payments Upon Termination or Change in Control

Under the applicable Award Unit grant agreements with each of the Named Executive Officers, if a Named Executive Officer is terminated by our General Partner or one of its affiliates (including the Company) without "Cause" (as defined below) or the Named Executive Officer resigns for "Good Reason" (as defined below) within the two-year period beginning on the occurrence of a "Change in Control" (as defined in the Long-Term Incentive Plan), then all unvested and outstanding Award Units (and all DERs corresponding to such Award Units) will vest in full as of such termination. In addition, the vesting of the Award Units may be accelerated in the discretion of the Board's compensation committee within the 30 days following certain terminations of the Named Executive Officers.

"Cause" is generally defined to mean (subject to notice and cure provisions for clauses (iii), (iv) and (v)): (i) conviction of, or plea of guilty or *nolo contendere* to, any felony or any crime involving theft, embezzlement, dishonesty or moral turpitude; (ii) any act constituting theft, embezzlement, fraud or similar conduct in the performance of the employee's duties with respect to the Company, the General Partner or one of their affiliates; (iii) any act constituting willful misconduct, deliberate malfeasance or gross negligence in the performance of the employee's duties with respect to the Company, the General Partner or one of their affiliates; (iv) willful and continued failure to perform any of the employee's duties; or (v) any material breach by the employee of the Long-Term Incentive Plan, any award agreement thereunder or any other agreement between the employee and the Company, the General Partner or one of their affiliates.

"Good Reason" is generally defined to mean (subject to customary notice and cure provisions): (i) a material diminution in title, position or duties; (ii) a material reduction in any component of the employee's compensation (provided that, for clarity, a reduction in the fair market value of any common units or other equity securities granted as compensation to the employee shall not be considered to be a reduction in compensation); (iii) relocation of the employee's primary office location by more than 50 miles; or (iv) any material breach by the Company, the General Partner or one of their affiliates of any agreement between the employee, on the one hand, and the Company, the General Partner or one of their affiliates, on the other hand, in each case, unless mutually agreed in writing.

Non-Employee Director Compensation

The Board has adopted a compensation program for our non-employee directors, or the "Non-Employee Director Compensation Policy." The Non-Employee Director Compensation Policy became effective as of October 27, 2023. Pursuant to the Non-Director Compensation Policy, each member of the Board who is not our employee will receive the following cash compensation for board services, as applicable:

a. $75,000 per year for service as a board member; and

b. an additional $25,000 per year for service as chairperson of the Audit Committee.

In addition, pursuant to the Non-Employee Director Compensation Policy, annually, on a date determined by the Board, each individual who serves as a non-employee director as of such date will receive grants of Award Units with a grant date value equal to approximately $150,000 and, for each such Award Unit, a corresponding DER, which entitles the director to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding. The Award Units (and their corresponding DERs) will vest on the earlier of (i) the first anniversary of the date of grant and (ii) a Change in Control (as defined in the Long-Term Incentive Plan), in each case, subject to such director's continuing service on the Board through such date or Change in Control, as applicable. Our Non-Employee Director Compensation Policy provides that the Award Units and corresponding DERs shall be granted under and shall be subject to the terms and provisions of the Long-Term Incentive Plan and shall be granted subject to the execution and delivery of award agreements.

Director Compensation Table

The following table summarizes the compensation awarded or paid to certain non-employee members of the Board for the fiscal year ended December 31, 2023. For summary information on the provision of the plans and programs, refer to the "Non-Employee Director Compensation" discussion immediately preceding this table.

Name	Fees Earned or Paid in Cash[1]	Stock Awards[2]	All other Compensation	Total
Edgar R. Giesinger	$ 25,000	$ 148,426	$ —	$ 173,426
Stephen Perich	$ 18,750	$ 148,426	$ —	$ 167,176
Francis A. Keating II	$ 18,750	$ 148,426	$ —	$ 167,176
William McMullen[3]	$ —	$ —	$ —	$ —

(1) Represents fees earned by or paid to our non-employee directors for services during calendar year 2023, including for services on board of our subsidiaries.

(2) On October 27, 2023, each of our non-employee directors (other than Mr. McMullen) received an award of 7,895 Award Units, each of which was granted with a corresponding DER. The amounts reflected in this column represent the grant date fair value of the Award Units granted to each of our non-employee directors pursuant to the Long-Term Incentive Plan, as computed in accordance with FASB ASC Topic 718. See Note 9 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report for details.

(3) Mr. McMullen does not receive compensation for his service as a member of the Board under the Non-Employee Director Compensation Policy because he is a service provider of Bayou City Energy, L.P. or its affiliates.

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

The following table sets forth certain information known to us, based on filings made under Section 13(d) and 13(g) of the Exchange Act, regarding the beneficial ownership of our common units as of March 15, 2024 by:

- each person, or group of affiliated persons, know to us to beneficially own more than 5% of our common units;
- each member of the board of directors of our general partner;
- each name executive officer of our general partner; and
- all of our directors and executive officers of our general partner as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Each of the holders listed has sole voting and investment power with respect to the common units beneficially owned by the holder unless noted otherwise, subject to community property laws where applicable. Unless otherwise noted, the address for each beneficial owner listed below is 14201 Wireless Way, Suite 300, Oklahoma City, OK 73134.

As of March 15, 2024, there were 95,000,000 common units outstanding.

	Common Units Beneficially Owned	
	Common Units	Percentage of Common Units
Name of Beneficial Owner:		
Investment funds managed by Bayou City Energy Management LLC[(1)]	68,226,633	71.8 %
Tom L. Ward[(2)]	13,639,511	14.4 %
Kevin R. White	698,299	*
Daniel T. Reineke, Jr.	698,299	*
Michael Reel	138,125	*
William McMullen[(1)]	68,226,633	71.8 %
Edgar R. Giesinger	—	— %
Stephen Perich	—	— %
Frank A. Keating	—	— %
All executive officers and directors as a group (8 persons)	83,400,867	87.8 %

* Less than 1%.

(1) Represents the common units held by BCE-Mach Aggregator LLC ("BCE Aggregator"). Investment funds managed by Bayou City Energy Management LLC controls the investment decisions of BCE Aggregator and William McMullen has management control over these investment funds and accordingly may be deemed to share beneficial ownership of the common units held by BCE Aggregator. William McMullen disclaims beneficial ownership of such common units. The principal address for each of the above referenced entities is c/o Bayou City Energy, L.P., 1201 Louisiana Street Suite 3308, Houston, TX 77002.

(2) Includes common units held through Mach Resources, over which Mr. Ward has control, and common units held in trust through the Tom L Ward 1992 Revocable Trust. Does not include common units owned by certain other trusts affiliated with Mr. Ward, which are not controlled by Mr. Ward, but for which an employee of Mach Resources serves as the trustee. Such common units owned by trusts affiliated with Mr. Ward currently represent approximately 1.7% of our outstanding common units. Does not include grants under the Long-Term Incentive Plan, with the number of common units underlying the award being 110,526 common units.

Equity Compensation Plan Information

The following table provides information with respect to our common units that may be issued under our existing equity compensation plans as of December 31, 2023.

Plan Category	Number of common units to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of common units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders			
Mach Natural Resources LP 2023 Long-Term Incentive Plan(1)	715,000	$—	8,785,000
Equity compensation plans not approved by unitholders			
None	—	$—	—
Total	715,000	$—	8,785,000

(1) All outstanding awards represent Award Units (each granted in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distribution paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding) subject to time-based vesting, which do not have an exercise price.

A description of the material terms of the Award Units (and correspondiong DERs) granted under the Long-Term Incentive Plan to our Named Executive Officers as of December 31, 2023 is included within "Executive Compensation— Equity Incentives— 2023 Long-Term Incentive Plan" in Item 11 of Part III of this Annual Report, which description is incorporated into this Equity Compensation Plan Information disclosure by reference. The Long-Term Incentive Plan is incorporated by reference herein as Exhibit 10.1.

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of the date hereof, the Sponsor owns 68,226,633 common units representing an approximate 71.8% limited partner interest in us, and BCE-Mach Aggregator, which is controlled by the Sponsor, owns 80.3% of our general partner. Tom L. Ward beneficially owns 13,639,511 common units representing an approximate 14.4% limited partner interest in us and beneficially owns 19.7% of our general partner through his ownership of Mach Resources. The Sponsor, who owns BCE-Mach Aggregator, and Tom L. Ward through his ownership of Mach Resources indirectly appoint all of the directors of our general partner, which owns a non-economic general partner interest in us.

Policies and Procedures for Review of Related Party Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved will or may be expected to exceed $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. A "Related Person" means:

- a person who is or was (since the beginning of the Company's last completed fiscal year, even if they do not presently serve in that role) a director or director nominee of the Company;
- a person who is or was (since the beginning of the Company's last completed fiscal year, even if they do not presently serve in that role) a senior officer of the Company, which, among others, includes each vice president and officer of the Company that is subject to reporting under Section 16 of the Exchange Act;
- a greater than 5% beneficial owner of the Company's common units representing limited partner interests (a "5% Unitholder");
- a person who is an immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of a director, director nominee, senior officer or 5% Unitholder, and any person (other than a tenant or employee) sharing the household of the director, director nominee, senior officer or 5% Unitholder; or
- an entity that is owned or controlled by someone listed above, an entity in which someone listed above has a substantial ownership interest or control of the entity, or an entity which someone listed above is an executive officer or general partner, or holds a similar position.

Our Related Party Transactions Policy (the "RPT Policy") was adopted by our Board of Directors in October 2023. The RPT Policy required that, prior to entering into a Related Party Transaction, the Audit Committee shall review the material facts of the proposed transaction in advance. If advance Audit Committee review and approval of a Related Party Transaction is not feasible, then such Related Party Transaction will be reviewed and considered and, if the Audit Committee determines it to be appropriate and not inconsistent with the interests of the Company and its stockholders, ratified at the Audit Committee's next regularly scheduled meeting. In determining whether to approve or ratify such a Related Party Transaction, the Audit Committee will take into account, among other factors it deems appropriate, (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances, (2) the extent of the Related Person's interest in the transaction and (3) whether the Related Party Transaction is material to the Company.

Unless otherwise stated, each of the Related Party Transactions discussed below were authorized or consummated prior to our adoption of the RPT Policy.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our ongoing operations and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm's length negotiations.

Operational Stage	
Distributions of available cash to affiliates of our general partner	We make cash distributions to our unitholders, including affiliates of our general partner, pro rata.
	The affiliates of our general partner (the Sponsor and Tom L. Ward through his ownership in Mach Resources) beneficially own 81,866,144 common units, representing approximately 86.2% of our outstanding common units and receive a pro rata percentage of the cash distributions that we distribute in respect thereof.
Payments to our general partner and its affiliates	The management, maintenance and operational functions of our business are currently provided by Mach Resources pursuant to the MSA. The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our general partner nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner with respect to any common units or other units then held by our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Management

Tom L. Ward, our Chief Executive Officer, and certain affiliated entities of Mr. Ward have royalty and working interests in certain of our wells. The payments related to these certain interests were $440,302, $595,474 and $451,933 for the years ended December 31, 2023, 2022 and 2021, respectively.

Management Services Agreements

The Mach Companies have previously entered into management services agreements with Mach Resources, pursuant to which Mach Resources managed and performed all aspects of oil and gas operations and other general and administrative functions of the Mach Companies. On a monthly basis, the Mach Companies reimbursed certain costs and expenses to Mach Resources for performance under the existing management services agreements. For the year ended December 31, 2023, the Company paid $52.3 million to Mach Resources, which consisted of $4.8 million for a management fee and $47.5 million for reimbursements of its costs and expenses under the existing management services agreements. For the year ended December 31, 2022, the Predecessor paid $33.7 million to Mach Resources, which consisted of $2.0 million for a management fee and $31.7 million for reimbursements of its costs and expenses under the existing management services agreements. For the year ended December 31, 2021, the Predecessor paid $23.6 million to Mach Resources, which consisted solely of reimbursements of its costs and expenses under the existing management services agreements. In connection with the Offering, the existing management services agreements with Mach Resources were terminated and replaced with the MSA.

Other Transactions with Related Persons

BCE-Stack is an affiliate of BCE-Mach Aggregator, a member of our Predecessor, and previously was an owner of working and revenue interests in a subset of our Predecessor's wells. BCE-Stack sold their interests in the wells to our

Predecessor on February 28, 2022. As of December 31, 2023 and 2022, we had no receivables or payables with BCE-Stack.

Agreements with Affiliates in Connection with the Corporate Reorganization

In connection with the closing of the Offering, we, our general partner and its affiliates entered into the various documents and agreements to effectuate the Corporate Reorganization. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations.

Contribution Agreement

In connection with the closing of the Offering, we entered into a contribution agreement (the "Contribution Agreement") that will effect the transactions whereby BCE, through its affiliate holding companies, contributed 100% of its membership interests in the Mach Companies not already owned by BCE-Mach Aggregator to BCE-Mach Aggregator in exchange for additional membership interests in BCE-Mach Aggregator. Each of BCE-Mach Aggregator, the Management Members and Mach Resources contributed 100% of their respective membership interests in the Mach Companies to the Company in exchange for a pro rata allocation of 100% of the limited partnership interests in the Company. Following the closing of the Offering and pursuant to the Contribution Agreement, the Company purchased from the contributing parties a portion of their limited partnership interests in the Company for cash with a portion of the proceeds of the Offering.

While we believe this agreement is on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it is not the result of arm's-length negotiations.

New Management Services Agreement

We also entered into a management services agreement ("MSA") with Mach Resources setting forth the operational services arrangements described below. Mach Resources is owned 50.5% by our Chief Executive Officer, Tom L. Ward, through the Tom L Ward 1992 Revocable Trust and 49.5% by WCT Resources LLC which is owned by certain trusts affiliated with Mr. Ward for which an employee of Mach Resources is trustee. Mach Resources will provide certain management, maintenance and operational functions with respect to our assets as fully described in the MSA (the "Services"). We will (i) pay Mach Resources an annual management fee of approximately $7.4 million and (ii) reimburse Mach Resources for the costs and expenses of the Services provided, including, but not limited to, (a) all reasonable third party costs and expenses incurred by or paid by Mach Resources or its Affiliates in the performance of the Services, including the costs of any Person engaged by Service Provider pursuant to the terms of the MSA, and (b) all general, administrative and supervision costs and expenses. We will reimburse Mach Resources on a quarterly basis or at other intervals that we and Mach Resources may agree from time to time. Payments under the MSA to Mach Resources were $52.3 million for the year ended December 31, 2023. We anticipate that the size of the reimbursements to Mach Resources will vary with the size and scale of our operations, among other factors. The MSA has an initial term of two years and automatically extends for successive extension terms of one year each, unless terminated by either party in accordance with the MSA. In the MSA, both us and Mach Resources, an affiliate of our general partner, and our respective affiliates agree to indemnify and hold harmless the other party from any and all losses arising out of or in connection with the agreement except for losses resulting from (i) fraud, gross negligence or willful misconduct of the other party, (ii) willful breach of the other party or (iii) employment claims made by Mach Resources employees.

Item 14. Principal Accountant Fees and Services

Our independent registered public accounting firm is Grant Thornton LLP, Oklahoma City, OK, Auditor Firm ID: 248.

Aggregate fees for professional services rendered for the Company by Grant Thornton LLP for the years ended December 31, 2023 and 2022, are presented in the following table.

	Year Ended December 31,	
(in thousands)	**2023**	**2022**
Audit fees	$ 1,884	$ 183
Audit-related fees	—	—
Tax fees	110	125
All other fees	—	—
Total	$ 1,994	$ 307

The Audit Committee has determined that Grant Thornton LLP is independent for purposes of providing external audit services to the Company.

Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services

The Audit Committee has adopted procedures for pre-approving all audit and non-audit services provided by its independent accounting firm. These procedures include reviewing fee estimates for audit services and permitted recurring non-audit services, and authorizing the Company to execute letter agreements setting forth such fees. Audit Committee approval is required for any services to be performed by the independent accounting firm that are not specified in the letter agreements. The Audit Committee has delegated approval authority to the chairman of the Audit Committee, but any exercises of such authority are reported to the Audit Committee at the next meeting.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

The Board has adopted policies for the review, approval and ratification of transactions with related persons. The Board has adopted a related party transactions policy, under which a director would be expected to bring to the attention of our General Counsel any conflict or potential conflict of interest that may arise between the director in his or her personal capacity or any affiliate of the director in his or her personal capacity, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the Board in light of the circumstances, be determined by our conflict committee or audit committee, as applicable.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the Board in accordance with the provisions of our partnership agreement. At the discretion of the Board in light of the circumstances, the resolution may be determined by the Board in its entirety, by the conflicts committee of the Board or by approval of our unitholders (other than the general partner and its affiliates).

Under our related party transactions policy, any executive officer will be required to avoid personal conflicts of interest unless approved by the Board.

The related party transactions policy described above was adopted in connection with the closing of the Offering, and as a result, the transactions described above were not reviewed according to such procedures.

Part IV

Item 15. Exhibit and Financial Statement Schedules

(a) Financial statements and financial statement schedules filed as part of this Annual Report are listed in the index included in Item 8 of Part II of this Annual Report. All valuation and qualifying accounts schedules have been omitted because they are either not material, not required, not applicable or the information required to be presented is included in our combined and consolidated financial statements and related notes.

(b) Exhibits. The following is a list of exhibits required to be filed as a part of this Annual Report in Item 15(b).

Exhibit Number	Description
2.1*†	Purchase and Sale Agreement, dated as of November 10, 2023, by and among Excalibur Resources, LLC, Travis Peak Resources, LLC, Paloma Partners IV, LLC and TPR Mid-Continent, LLC, as sellers, and Mach Natural Resources LP, as buyer (incorporated by reference to Exhibit 2.1 of the Partnership's Form 8-K filed on November 13, 2023).
3.1*	Certificate of Limited Partnership of Mach Natural Resources LP (incorporated by reference to Exhibit 3.1 to the Partnership's Form S-1 (File No. 333-274662) filed on September 22, 2023).
3.2*	Amended and Restated Agreement of Limited Partnership of Mach Natural Resources LP (incorporated by reference to Exhibit 3.1 of the Partnership's Form 8-K filed on October 27, 2023).
3.3*	Amended and Restated Limited Liability Company Agreement of Mach Natural Resources GP, LLC (incorporated by reference to Exhibit 3.3 of the Partnership's Form 10-Q filed on December 7, 2023).
10.1*††	Mach Natural Resources LP 2023 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 of the Partnership's Form 8-K filed on October 27, 2023).
10.2*	Form of Mach Natural Resources LP 2023 Long-Term Incentive Plan Phantom Unit Agreement (Non-Employee Directors) (incorporated by reference to Exhibit 4.4 of the Partnership's Form S-8 filed on October 27, 2023)
10.3*	Form of Mach Natural Resources LP 2023 Long-Term Incentive Plan Phantom Unit Agreement (Executives) (incorporated by reference to Exhibit 4.5 of the Partnership's Form S-8 filed on October 27, 2023)
10.4*	Contribution Agreement, dated October 13, 2023, by and among Mach Natural Resources LP, Mach Natural Resources Holdco LLC, Mach Natural Resources Intermediate LLC and the other contributors party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on October 27, 2023).
10.5*	Management Services Agreement, dated October 27, 2023, by and between Mach Natural Resources LP and Mach Resources LLC (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on October 27, 2023).
10.6*	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to the Partnership's Registration Statement on Form S-1, filed on September 29, 2023, File No. 333-274662).
10.7*	Term Loan Credit Agreement, dated December 28, 2023, among Mach Natural Resources LP, the guarantors party thereto, the lenders party thereto, Texas Capital Bank, as the administrative agent, and Chambers Energy Management, LP, as the loan commitment arranger (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on December 29, 2023).
10.8*	Revolving Credit Agreement, dated December 28, 2023, among Mach Natural Resources LP, the guarantors party thereto, the lenders party thereto and MidFirst Bank, as the administrative agent (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on December 29, 2023).
10.9*	Third Amendment to Credit Agreement, among BCE-Mach III LLC, as borrower, BCE-Mach III Midstream Holdings LLC, as guarantor, the several lenders from time to time parties thereto, and MidFirst Bank as administrative agent, collateral agent issuing bank and lender, dated January 27, 2023 (incorporated by reference to Exhibit 10.14 to the Partnership's Form S-1 (File No. 333-274662) filed on September 22, 2023).
10.10*	Amended and Restated Credit Agreement, dated November 10, 2023, among Mach Natural Resources Holdco LLC, as borrower, the several lenders from time to time parties thereto and MidFirst Bank, as administrative agent and collateral agent for the lenders (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on November 10, 2023).
21.1**	List of Subsidiaries of Mach Natural Resources LP.
23.1**	Consent of Grant Thornton LLP.
23.2**	Consent of Cawley, Gillespie & Associates.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.

32.1***	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2***	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
97.1**	Clawback Policy of Mach Natural Resources LP.
99.1**	Report of Cawley, Gillespie & Associates of reserves of Mach Natural Resources LP, as of December 31, 2023.
101.INS**	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because XBRL tags are embedded within the Inline XBRL document
101.SCH**	Inline XBRL Taxonomy Extension Schema Document
101.CAL**	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104**	Cover Page Interactive Data File (embedded within the Inline XBRL document)

____

*	Incorporated herein by reference as indicated.
**	Filed herewith.
***	Furnished herewith.
†	Certain of the schedules and exhibits to the agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished to the SEC upon request.
††	Management contract of compensatory plan or agreement.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Mach Natural Resources LP
(Registrant)

By: **Mach Natural Resources GP LLC, its general partner**

Date: April 1, 2024

By:	/s/ Tom L. Ward
Name:	Tom L. Ward
Title:	Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on April 1, 2024.

Name	Title
/s/ Tom L. Ward Tom L. Ward	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Kevin R. White Kevin R. White	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
/s/ William McMullen William McMullen	Chairman of the Board
/s/ Edgar R. Giesinger Edgar R. Giesinger	Director
/s/ Stephen Perich Stephen Perich	Director
/s/ Francis A. Keating II Francis A. Keating II	Director

Exhibit 21.1

SUBSIDIARIES OF MACH NATURAL RESOURCES LP

Name of Subsidiary	Jurisdiction of Organization
Mach Natural Resources Intermediate LLC	Delaware
Mach Natural Resources Holdco LLC	Delaware
BCE-Mach LLC	Delaware
BCE-Mach II LLC	Delaware
BCE-Mach III LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated April 1, 2024, with respect to the consolidated financial statements included in the Annual Report of Mach Natural Resources LP on Form 10-K for the year ended December 31, 2023. We consent to the incorporation by reference of said report in the Registration Statement of Mach Natural Resources LP on Form S-8 (File No. 333-275200).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

April 1, 2024

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to, and the inclusion of, our summary reserve report dated January 22, 2024, and oil, natural gas and NGL reserves estimates and forecasts of economics as of December 31, 2023, included in or made part of this Annual Report on Form 10-K of Mach Natural Resources LP. We also consent to the incorporation by reference of such report in the Registration Statement (Form S-8 No. 333-275200) of Mach Natural Resources LP.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm

/s/ J. Zane Meekins

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
April 1, 2024

Exhibit 31.1

CERTIFICATION

I, Tom L. Ward, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mach Natural Resources LP;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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) [Reserved];

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

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

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

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

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

Date: April 1, 2024

/s/ Tom L. Ward
Tom L. Ward
Chief Executive Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 31.2

CERTIFICATION

I, Kevin R. White, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mach Natural Resources LP;

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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) [Reserved];

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

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

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

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

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

Date: April 1, 2024

/s/ Kevin R. White
Kevin R. White
Chief Financial Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 32.1

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

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of Mach Natural Resources LP (the "Company") hereby certifies, to such officer's knowledge, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2023 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: April 1, 2024

/s/ Tom L. Ward
Tom L. Ward
Chief Executive Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 32.2

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

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of Mach Natural Resources LP (the "Company") hereby certifies, to such officer's knowledge, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2023 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: April 1, 2024

/s/ Kevin R. White
Kevin R. White
Chief Financial Officer
Mach Natural Resources GP, LLC, its general partner

CLAWBACK POLICY

PURPOSE

The board of directors (the “Board”) of Mach Natural Resources GP LLC (the “General Partner”), the general partner of Mach Natural Resources LP (the “Partnership”), believes that it is in the best interests of the Partnership and its unitholders to create and maintain a culture that emphasizes integrity and accountability and that reinforces the Partnership’s pay-for-performance compensation philosophy. The Board has therefore adopted this policy, which provides for the recoupment of certain executive compensation in the event that the Partnership is required to prepare an accounting restatement of its financial statements due to material noncompliance with any financial reporting requirement under the federal securities laws (this “Policy”). This Policy is designed to comply with Section 10D of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), the rules promulgated thereunder, and the listing standards of the national securities exchange on which the Partnership’s securities are listed.

ADMINISTRATION

This Policy shall be administered by the Compensation Committee of the Board (the “Compensation Committee”). Any determinations made by the Compensation Committee shall be final and binding on all affected individuals.

COVERED EXECUTIVES

This Policy applies to the General Partner’s and the Partnership’s current and former executive officers (as determined by the Compensation Committee in accordance with Section 10D of the Exchange Act, the rules promulgated thereunder, and the listing standards of the national securities exchange on which the Partnership’s securities are listed) and such other senior executives or employees who may from time to time be deemed subject to this Policy by the Compensation Committee (collectively, the “Covered Executives”). This Policy shall be binding and enforceable against all Covered Executives.

RECOUPMENT; ACCOUNTING RESTATEMENT

In the event that the Partnership is required to prepare an accounting restatement of its financial statements due to the Partnership’s material noncompliance with any financial reporting requirement under the securities laws, including any required accounting restatement (i) to correct an error in previously issued financial statements that is material to the previously issued financial statements, or (ii) that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (each an “Accounting Restatement”), the Compensation Committee will reasonably promptly require reimbursement or forfeiture of the Overpayment (as defined below) received by any Covered Executive (x) after beginning service as a Covered Executive, (y) who served as a Covered Executive at any time during the performance period for the applicable Incentive-Based Compensation (as defined below), and (z) during the three (3) completed fiscal years immediately preceding the date on which the Partnership is required to prepare an Accounting Restatement and any transition period (that results from a change in the Partnership’s fiscal year) within or immediately following those three (3) completed fiscal years.

INCENTIVE-BASED COMPENSATION

For purposes of this Policy, “Incentive-Based Compensation” means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a financial reporting measure, including, but not limited to: (i) non-equity incentive plan awards that are earned solely or in part by satisfying a financial reporting measure performance goal; (ii) bonuses paid from a bonus pool, where the size of the pool is determined solely or in part by satisfying a financial reporting measure performance goal; (iii) other cash awards based on satisfaction of a financial reporting measure performance goal; (iv) options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights, common units and other unit-based awards that are granted or vest solely or in part based on satisfaction of a financial reporting measure performance goal; and (v) proceeds from the sale of units acquired through an incentive plan that were granted or vested solely or in part based on satisfaction of a financial reporting measure performance goal.

Compensation that would not be considered Incentive-Based Compensation includes, but is not limited to: (i) salaries; (ii) bonuses paid solely based on satisfaction of subjective standards, such as demonstrating leadership, and/or completion of a specified employment period; (iii) non-equity incentive plan awards earned solely based on satisfaction of strategic or operational measures; (iv) wholly time-based equity awards; and (v) discretionary bonuses or other compensation that is not paid from a bonus pool that is determined by satisfying a financial reporting measure performance goal.

A financial reporting measure is: (i) any measure that is determined and presented in accordance with the accounting principles used in preparing financial statements, or any measure derived wholly or in part from such measure, such as revenues, EBITDA, or net income or (ii) unit price and total unitholder return. Financial reporting measures include, but are not limited to: revenues; net income; operating income; profitability of one or more reportable segments; financial ratios (e.g., accounts receivable turnover and inventory turnover rates); net assets or net asset value per unit; earnings before interest, taxes, depreciation and amortization; funds from operations and adjusted funds from operations; liquidity measures (e.g., working capital, operating cash flow); return measures (e.g., return on invested capital, return on assets); earnings measures (e.g., earnings per unit); sales per square foot or same store sales, where sales is subject to an accounting restatement; revenue per user, or average revenue per user, where revenue is subject to an accounting restatement; cost per employee, where cost is subject to an accounting restatement; any of such financial reporting measures relative to a peer group, where the Partnership's financial reporting measure is subject to an accounting restatement; and tax basis income.

OVERPAYMENT: AMOUNT SUBJECT TO RECOVERY

The amount to be recovered will be the amount of Incentive-Based Compensation received that exceeds the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the restated amounts, and must be computed without regard to any taxes paid (the "Overpayment"). Incentive-Based Compensation is deemed "received" in the Partnership's fiscal period during which the financial reporting measure specified in the applicable Incentive-Based Compensation award is attained, even if the vesting, payment or grant of such Incentive-Based Compensation occurs after the end of that period.

For Incentive-Based Compensation based on unit price or total unitholder return, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in the Accounting Restatement, the amount must be based on a reasonable estimate of the effect of the Accounting Restatement on the unit price or total unitholder return upon which the Incentive-Based Compensation was received, and the Partnership must maintain documentation of the determination of that reasonable estimate and provide such documentation to the exchange on which the Partnership's securities are listed.

METHOD OF RECOUPMENT

The Compensation Committee will determine, in its sole discretion, the method or methods for recouping any Overpayment hereunder which may include, without limitation:

- requiring reimbursement of cash Incentive-Based Compensation previously paid;
- seeking recovery of any gain realized on the vesting, exercise, settlement, sale, transfer, or other disposition of any equity-based awards granted as Incentive-Based Compensation;
- offsetting any or all of the Overpayment from any compensation otherwise owed by the Partnership or the General Partner to the Covered Executive;
- cancelling outstanding vested or unvested equity awards; and/or
- taking any other remedial or recovery action permitted by law, as determined by the Compensation Committee.

LIMITATION ON RECOVERY; NO ADDITIONAL PAYMENTS

The right to recovery will be limited to Overpayments received during the three (3) completed fiscal years prior to the date on which the Partnership is required to prepare an Accounting Restatement and any transition period (that results from a change in the Partnership's fiscal year) within or immediately following those three (3) completed fiscal years. In no event shall the Partnership be required to award Covered Executives an additional payment if the restated or accurate financial results would have resulted in a higher Incentive-Based Compensation payment.

NO INDEMNIFICATION

The Partnership shall not indemnify any Covered Executives against the loss of any incorrectly awarded Incentive-Based Compensation.

INTERPRETATION

The Compensation Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. It is intended that this Policy be interpreted in a manner that is consistent with the requirements of Section 10D of the Exchange Act and the applicable rules or standards adopted by the Securities and Exchange Commission or any national securities exchange on which the Partnership's securities are listed.

EFFECTIVE DATE

This Policy shall be effective as of the date it is adopted by the Board (the "Effective Date") and shall apply to Incentive-Based Compensation (including Incentive-Based Compensation granted pursuant to arrangements existing prior to the Effective Date). Notwithstanding the foregoing, this Policy shall only apply to Incentive-Based Compensation received (as determined pursuant to this Policy) on or after the closing of our initial public offering.

AMENDMENT; TERMINATION

The Board may amend this Policy from time to time in its discretion. The Board may terminate this Policy at any time.

OTHER RECOUPMENT RIGHTS

The Board intends that this Policy will be applied to the fullest extent of the law. The Compensation Committee may require that any employment or service agreement, cash-based bonus plan or program, equity award agreement, or similar agreement entered into on or after the adoption of this Policy shall, as a condition to the grant of any benefit thereunder, require a Covered Executive to agree to abide by the terms of this Policy. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Partnership pursuant to the terms of any similar policy in any employment agreement, equity award agreement, cash-based bonus plan or program, or similar agreement and any other legal remedies available to the Partnership.

IMPRACTICABILITY

The Compensation Committee shall recover any Overpayment in accordance with this Policy except to the extent that the Compensation Committee determines such recovery would be impracticable because:

(A) The direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered;

(B) Recovery would violate home country law of the Partnership where that law was adopted prior to November 28, 2022; or

(C) Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Partnership or the General Partner, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

SUCCESSORS

This Policy shall be binding and enforceable against all Covered Executives and their beneficiaries, heirs, executors, administrators or other legal representatives.

Exhibit 99.1

Cawley, Gillespie & Associates, Inc.
PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, BLDG 3 SUITE 200 306 WEST SEVENTH STREET, SUITE 302 1000 LOUISIANA STREET, SUITE 1900
AUSTIN, TEXAS 78730 FORT WORTH, TEXAS 76102-4905 HOUSTON, TEXAS 77002-5017
512-249-7000 817- 336-2461 713-651-9944
www.cgaus.com

January 22, 2024

John Bergman
Vice President - Reservoir Engineering
Mach Natural Resources LP
14201 Wireless Way
Oklahoma City, OK 73134

Re: Evaluation Summary – SEC Pricing
Mach Natural Resources LP Interests
Oklahoma, Texas and Kansas
Proved Reserves
As of December 31, 2023

Dear Mr. Bergman:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the Mach Natural Resources LP ("Mach") interests in properties located in Oklahoma, Texas and Kansas. It is our understanding that the proved reserves estimated in this report constitute 100 percent of all proved reserves owned by Mach.

This report, completed on January 22, 2024, utilized an effective date of December 31, 2023, and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Proved Undeveloped	Proved
Net Reserves						
Oil	- Mbbl	48,628.9	1,000.8	0.0	25,943.8	75,573.4
Gas	- MMcf	896,197.3	13,174.3	0.0	197,102.3	1,106,473.8
NGL	- Mbbl	68,153.2	1,039.9	0.0	16,472.0	85,665.1
Revenue						
Oil	- M$	3,729,306.7	76,784.4	0.0	1,996,076.9	5,802,164.9
Gas	- M$	1,477,117.4	13,079.0	0.0	311,441.6	1,801,638.3
NGL	- M$	1,612,728.5	21,723.2	0.0	443,495.3	2,077,946.9
Other	- M$	47,395.6	0.0	0.0	0.0	47,399.3
Severance and Ad Valorem Taxes	- M$	561,245.1	8,085.3	5.0	166,957.6	736,293.0
Operating Expenses	- M$	2,548,246.8	32,042.8	0.0	514,500.1	3,094,789.7
Investments	- M$	202,615.1	4,959.4	63,840.3	826,252.5	1,097,667.2
Operating Income (BFIT)	- M$	3,554,440.4	66,499.1	-63,845.4	1,243,303.6	4,800,398.8
Discounted at 10.0%	- M$	2,082,001.1	20,205.2	-11,887.9	486,539.9	2,576,858.9

We evaluated cases that comprise over 95% of the cumulative discounted cash flows of the proved developed producing reserves from the company's internal evaluation of the upstream cases and 100% of the reserves in the remaining categories. We refer to these cases as the "Major Upstream" properties, and composite reserve estimates and economic forecasts for these properties are summarized below:

		Major Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Proved Undeveloped
Net Reserves					
Oil	- Mbbl	45,199.3	1,000.8	0.0	25,943.8
Gas	- MMcf	780,716.9	13,174.3	0.0	197,102.3
NGL	- Mbbl	60,161.9	1,039.9	0.0	16,472.0
Revenue					
Oil	- M$	3,468,698.2	76,784.4	0.0	1,996,076.9
Gas	- M$	752,709.5	13,079.0	0.0	236,771.2
NGL	- M$	1,370,189.9	21,723.2	0.0	443,495.3
Other	- M$	0.0	0.0	0.0	0.0
Severance and Ad Valorem Taxes	- M$	398,494.5	8,085.3	5.0	166,957.6
Operating Expenses	- M$	1,621,903.2	32,042.8	0.0	522,496.1
Investments	- M$	73,089.7	4,959.4	63,840.3	826,252.5
Operating Income (BFIT)	- M$	3,498,109.7	66,499.1	-63,845.4	1,160,637.5
Discounted at 10.0%	- M$	1,868,957.3	20,205.2	-11,887.9	444,778.7

The remaining upstream cases are referred to as the "Minor Upstream" properties, and the company's internal reserve estimates and economic forecasts for these properties are summarized below:

		Minor Proved Developed Producing
Net Reserves		
Oil	- Mbbl	3,429.6
Gas	- MMcf	115,480.4
NGL	- Mbbl	7,991.3
Revenue		
Oil	- M$	260,608.6
Gas	- M$	159,053.4
NGL	- M$	170,032.8
Other	- M$	0.0
Severance and Ad Valorem Taxes	- M$	45,278.1
Operating Expenses	- M$	315,108.9
Investments	- M$	129,525.4
Operating Income (BFIT)	- M$	99,781.7
Discounted at 10.0%	- M$	84,732.1

Composite forecasts of revenues and expenses for company-owned plants, gas gathering systems and water disposal systems are summarized below:

		Major Proved Developed Producing Midstream	Minor Proved Developed Producing Midstream	Proved Undeveloped Midstream	Total Proved Midstream
Net Reserves					
Oil	- Mbbl	0.0	0.0	0.0	0.0
Gas	- MMcf	0.0	0.0	0.0	0.0
NGL	- Mbbl	0.0	0.0	0.0	0.0
Revenue					
Oil	- M$	0.0	0.0	0.0	0.0
Gas	- M$	565,354.8	0.0	74,670.4	640,025.2
NGL	- M$	72,505.9	0.0	0.0	72,505.9
Other	- M$	9,881.8	37,513.1	0.0	47,394.9
Severance and					
Ad Valorem Taxes	- M$	117,472.5	0.0	0.0	117,472.5
Operating Expenses	- M$	582,536.2	28,696.9	-7,996.0	603,237.2
Investments	- M$	0.0	0.0	0.0	0.0
Operating Income (BFIT)	- M$	-52,266.3	8,816.2	82,666.4	39,216.3
Discounted at 10.0%	- M$	123,968.7	4,341.4	41,761.2	170,071.3

The above revenues and expenses are limited to those associated only with Mach volumes. No revenues resulting from the gathering or processing of third party volumes are included. The minor proved developed producing revenues and expenses are from the company's internal evaluation of the midstream cases.

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $2.637 per MMBtu and the annual average WTI Cushing spot oil price of $78.22 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $76.78 per barrel of oil, $1.63 per Mcf of gas, and $24.26 per barrel of NGL.

Operating expenses and capital costs were supplied by Mach and reviewed for reasonableness. Severance taxes were forecast by state based on statutory rates, and ad valorem taxes were forecast as 3.0% of net revenue for operated properties in Texas and Kansas. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final

Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Natural Resources LP. Ownership interests were supplied by Mach Natural Resources LP and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Natural Resources LP as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

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