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, 2021

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: 1-13283

RANGER OIL CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

16285 Park Ten Place, Suite 500
Houston, TX 77084
(Address of principal executive offices) (Zip Code)

(713) 722-6500
(Registrant's telephone number, including area code)

Penn Virginia Corporation
(Former names or former address, if changed since last report)

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

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Class A Common Stock, $0.01 Par Value	**ROCC**	**The Nasdaq Stock Market LLC**

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

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

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

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

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

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

Large accelerated filer	☐	Accelerated filer	☒	Non-accelerated filer	☐	Smaller reporting company	☒	Emerging growth company	☐

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

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was $ 360,656,066 as of June 30, 2021 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the Nasdaq Global Select Market.

As of March 4, 2022, there were 43,664,292 shares of common stock outstanding, including 21,115,294 shares of Class A Common Stock and 22,548,998 shares of Class B Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 2, 2022, are incorporated by reference in Part III of this Form 10-K.

RANGER OIL CORPORATION
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2021

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Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We use words such as "anticipate," "guidance," "assumptions," "projects," "estimates," "expects," "continues," "intends," "plans," "believes," "forecasts," "future," "potential," "may," "possible," "could" and variations of such words or similar expressions to identify forward-looking statements. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- risks related to the fourth quarter 2021 acquisition of Lonestar Resources US Inc., including the risk that the benefits of the acquisition may not be fully realized or may take longer to realize than expected, and that management attention will be diverted to integration-related issues;
- risks related to other completed acquisitions and dispositions, including our ability to realize their expected benefits;
- the decline in, sustained market uncertainty of, and volatility of commodity prices for crude oil, natural gas liquids, or NGLs, and natural gas;
- the impact of the COVID-19 pandemic, including reduced demand for oil and natural gas, economic slowdown, governmental actions, stay-at-home orders, interruptions to our operations or our customer's operations;
- risks related to and the impact of actual or anticipated other world health events;
- our ability to satisfy our short-term and long-term liquidity needs, including our ability to generate sufficient cash flows from operations or to obtain adequate financing, including access to the capital markets, to fund our capital expenditures and meet working capital needs;
- our ability to access capital, including through lending arrangements and the capital markets, as and when desired;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in volatile commodity price environments;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- changes to our drilling and development program;
- our ability to generate profits or achieve targeted reserves in our development operations;
- our ability to meet guidance, market expectations and internal projections, including type curves;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, materials, supplies and services at reasonable costs;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity or other transportation for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from that estimated in our proved oil and gas reserves;
- use of new techniques in our development, including choke management and longer laterals;
- drilling, completion and operating risks, including adverse impacts associated with well spacing and a high concentration of activity;

- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for substantially all of our revenues and production;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties and economic events relating to general domestic and international economic and political conditions, including political tensions or war;
- the impact and costs associated with litigation or other legal matters;
- sustainability initiatives; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, or SEC, including the risks set forth in Part I, Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2021.

Additional information concerning these and other factors can be found in our press releases and public filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

Glossary of Certain Terms

The following abbreviations, terms and definitions are commonly used in the oil and gas industry and are used within this Annual Report on Form 10-K.

bbl. A standard barrel of 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

boe. One barrel of oil equivalent with 6,000 cubic feet of natural gas converted to one barrel of crude oil based on the estimated relative energy content.

boe/d. Barrels of oil equivalent per day.

Borrowing base. The value assigned to a collection of borrower's assets used by lenders to determine an initial and/or continuing amount for loans. In the case of oil and gas exploration and development companies, the borrowing base is generally based on proved developed reserves.

Completion. A process of treating a drilled well, including hydraulic fracturing among other stimulation processes, followed by the installation of permanent equipment for the production of oil or gas.

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

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

Dry hole. A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion of the well.

EBITDAX. A measure of profitability utilized in the oil and gas industry representing earnings before interest, income taxes, depreciation, depletion, amortization and exploration expenses. EBITDAX is not a defined term or measure in generally accepted accounting principles, or GAAP (see below).

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, a service well or a stratigraphic test well.

EUR. Estimated ultimate reserves, the sum of reserves remaining as of a given date and cumulative production as of that date.

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

Gas lift. A method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas for lifting the well fluids.

Gross acre or well. An acre or well in which a working interest is owned.

HBP. Held by production is a provision in an oil and gas or mineral lease that perpetuates the leaseholder's right to operate the property as long as the property produces a minimum paying quantity of oil or gas.

HH. Henry Hub, the Erath, Louisiana settlement point price for natural gas.

LIBOR. London Interbank Offered Rate.

LLS. Light Louisiana Sweet, a crude oil pricing index reference.

Mbbl. One thousand barrels of oil or other liquid hydrocarbons.

Mboe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MEH. Magellan East Houston, a crude oil pricing index reference.

MMbbl. One million barrels of oil or other liquid hydrocarbons.

MMboe. One million barrels of oil equivalent.

MMBtu. One million British thermal units, a measure of energy content.

MMcf. One million cubic feet of natural gas.

Mt. Belvieu. Mont Belvieu, a natural gas liquid pricing index reference.

Net acre or well. The number of gross acres or wells multiplied by the owned working interest in such gross acres or wells.

NGL. Natural gas liquid (includes ethane, propane, butane, isobutane, pentane and pentanes plus).

NYMEX. New York Mercantile Exchange.

Oil. Includes crude oil and condensate.

Operator. The entity responsible for the exploration and/or production of a lease or well.

OPIS. Oil Price Information Service.

Play. A geological formation with potential oil and gas reserves.

Productive wells. Wells that are not dry holes.

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

Proved developed reserves. Proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled.

PV10. A non-GAAP measure representing the present value of estimated future oil and gas revenues, net of estimated direct costs, discounted at an annual discount rate of 10%. PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for any GAAP measure. PV10 does not purport to represent the fair value of oil and gas properties.

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

Revenue interest. An economic interest in production of hydrocarbons from a specified property.

Royalty interest. An interest in the production of a well entitling the owner to a share of production generally free of the costs of exploration, development and production.

SEC. United States Securities and Exchange Commission.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

Standardized measure. The present value, discounted at 10% per year, of estimated future cash inflows from the production of proved reserves, computed by applying prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), reduced by estimated future development and production costs, computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year (including the settlement of asset retirement obligations), based on year-end costs and assuming continuation of existing economic conditions, further reduced by estimated future income tax expenses, computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the proved oil and gas reserves, less the tax basis of the properties involved and giving effect to the tax deductions and tax credits and allowances relating to the proved oil and gas reserves.

Unconventional. Generally refers to hydrocarbon reservoirs that lack discrete boundaries that typically define conventional reservoirs. Examples include shales, tight sands or coal beds.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves. Under appropriate circumstances, undeveloped acreage may not be subject to expiration if properly held by production, as that term is defined above.

WTI. West Texas Intermediate, a crude oil pricing index reference.

Working interest. A cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease.

RISK FACTOR SUMMARY

The following summarizes the principal factors that make an investment in Ranger Oil speculative or risky, all of which are more fully described in Part I, Item 1A. "Risk Factors" below. This summary should be read in connection with the Risk Factors section and should not be relied upon as an exhaustive summary of the material risks facing our business.

The following factors could materially adversely affect our business, results of operations, financial condition, cash flows, liquidity and the trading price of our common stock.

Risks Associated with our General Business

- The direct and indirect effects of the COVID-19 pandemic on our business, financial position, results of operations and/or cash flows, which will depend on future developments that are highly uncertain and cannot be predicted
- Prices for crude oil, NGLs and natural gas, which are dependent on many factors that are beyond our control
- Risks associated with drilling and operations activities, which are high-risk activities with many uncertainties and may not result in commercially productive reserves
- Risks associated with multi-well pad drilling and project development, which may result in volatility in our operating results
- Adverse impacts associated with a high concentration of activity and tighter drilling spacing
- Our ability to adhere to our proposed drilling schedule
- Our dependence on gathering, processing, refining and transportation facilities owned by others
- The unavailability, high cost or shortage of drilling rigs, frac crews, equipment, raw materials, supplies, oilfield services or personnel, which may restrict our operations
- Our ability to find or acquire additional oil and gas reserves that are economically recoverable
- Our ability to attract and retain key members of management, qualified Board members and other key personnel
- Our ability to establish production on the acreage of certain of our undeveloped leasehold assets that are subject to leases that will expire over the next several years unless production is developed
- Actions we or other operators may take when drilling, completing, or operating wells that they own that may adversely affect certain of our wells
- Our exposure to the credit risk of our customers
- Our participation in oil and gas leases with third parties, who may not be able to fulfill their commitments to our projects
- The accuracy of our estimates of oil and gas reserves and future net cash flows, which are not precise, and undeveloped reserves, which may not ultimately be converted into proved producing reserves
- The incurrence of impairments on our oil and gas properties
- Our ability to obtain sufficient capital
- Risks associated with property and business acquisitions
- Losses resulting from title deficiencies
- Difficulties associated with being a small company competing in a larger market
- Our lack of diversification and risks associated with operating primarily in one major contiguous area
- Operating risks, including risks associated with hydraulic fracturing

Financial and Related Risks

- Our substantial indebtedness
- A reduction in our borrowing base
- Restrictive covenants under the Credit Facility and the indenture governing our 9.25% Senior Notes due 2026 (the "Indenture"), which could limit our financial flexibility
- Derivative transactions, which may limit our potential gains and involve other risks
- Investor sentiment towards the oil and gas industry, which could adversely affect our ability to raise equity and debt capital

Legal and Regulatory Risks

- Various laws and regulations that could adversely affect the cost, manner or feasibility of doing business, including climate change legislation, laws and regulations restricting emissions of greenhouse gases or prohibiting, restricting, or delaying oil and gas development on public lands, and federal state and local legislation and regulatory initiatives relating to hydraulic fracturing
- Our ability to access water to drill and conduct hydraulic fracturing and difficulties associated with disposing of produced water gathered from drilling and production activities
- Risks associated with legal proceedings

Tax-Related Risks

- Our ability to use net operating loss carryforwards to offset future taxable income, which may be subject to certain limitations
- The continued availability of certain federal income tax deductions with respect to oil and gas exploration and development

Technology-Related Risks

- Our ability to keep pace with technological developments in our industry
- Risks relating to cybersecurity incidents

Risks Related to Ownership of Our Class A Common Stock

- Risks associated with Juniper's control of the Company, including potential conflicts between Juniper's interests and the interests of the Company and its stockholders
- Certain provisions of our certificate of incorporation and our bylaws that may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial
- The volatility of the market price of our Class A common stock
- The actions of so-called "activist" shareholders, which could impact the trading value of our securities
- Future sales or other dilution of our equity, which may adversely affect the market price of our Class A common stock

Part I

Item 1. Business

Unless the context requires otherwise, references to the “Company,” “Ranger Oil,” “we,” “us” or “our” in this Annual Report on Form 10-K refer to Ranger Oil Corporation and its subsidiaries.

Description of Business

We are an independent oil and gas company engaged in the onshore development and production of crude oil, NGLs and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the “Eagle Ford”) in South Texas.

On January 15, 2021 (the “Juniper Closing Date”), the Company consummated the transactions, (collectively, the “Juniper Transactions”), contemplated by: (i) the Contribution Agreement, dated November 2, 2020 (the “Contribution Agreement”), by and among the Company, PV Energy Holdings, L.P. (the “Partnership”), and JSTX Holdings, LLC (“JSTX”), an affiliate of Juniper Capital Advisors, L.P. (“Juniper Capital”), and, together with its affiliates (“Juniper”); and (ii) the Contribution Agreement, dated November 2, 2020 (the “Asset Agreement”, and, together with the Contribution Agreement, the “Juniper Transaction Agreements”), by and among Rocky Creek Resources, LLC, an affiliate of Juniper Capital (“Rocky Creek”), the Company and the Partnership, pursuant to which Juniper contributed $150 million in cash and certain oil and gas assets in South Texas in exchange for equity that entitles Juniper to both vote and share in any dividend on the same basis as 22,548,998 shares of our Class A Common Stock, par value $0.01 per share (“Class A Common Stock”) (after post-closing adjustments). See Note 4 to the consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data” of this Annual Report on 10-K for further information.

On October 5, 2021, the Company acquired Lonestar Resources US Inc., a Delaware corporation (“Lonestar”), as a result of which Lonestar and its subsidiaries became wholly-owned subsidiaries of the Company (the“Lonestar Acquisition”). Through the Lonestar Acquisition, we acquired certain oil and gas assets, including oil and gas leases covering approximately 51,000 net acres located primarily in the Eagle Ford Shale. Following the completion of the Lonestar Acquisition, the Company changed its name from Penn Virginia Corporation (“Penn Virginia”) to Ranger Oil Corporation and its ticker symbol from “PVAC” to “ROCC.” See Note 4 to the consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data” of this Annual Report on Form 10-K for further information.

Our headquarters and corporate office is located in Houston, Texas. We also have field operations offices near our Eagle Ford assets in South Texas. In conjunction with the Lonestar Acquisition, we acquired Lonestar’s corporate office in Fort Worth that is classified as held for sale at December 31, 2021 on our consolidated balance sheets in the consolidated financial statements in Part II, Item 8, “Financial Statements and Supplementary Data.”

Current Operations

We lease a highly contiguous position of approximately 170,900 gross (139,900 net) acres as of March 4, 2022 in the core liquids-rich area or “volatile oil window” of the Eagle Ford in South Texas, which we believe contains a substantial number of drilling locations that will support a multi-year drilling inventory.

In 2021, our total sales volume was comprised of 76% crude oil, 13% NGLs and 11% natural gas. Crude oil accounted for 90% of our product revenues. We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts.

As of December 31, 2021, our total proved reserves were approximately 241 MMboe, of which 38% were proved developed reserves and 68% were crude oil. As of December 31, 2021, we had 860 gross (724.5 net) productive wells, approximately 95% of which we operate, and leased approximately 172,000 gross (140,900 net) acres of leasehold and royalty interests, approximately 42% of which were undeveloped. Approximately 94% of our total acreage was HBP as of December 31, 2021 and included a substantial number of undrilled locations. During 2021, we completed and turned in line 46 gross (40.4 net) wells. For additional information regarding our production, reserves, drilling activities, wells and acreage, see Part I, Item 2, “Properties.”

Business Strategy

Our business strategy is focused on long-term shareholder value through employing rigorous capital discipline, employment of drilling and completion advanced technologies, and continuous operational improvements to create strong cash-on-cash returns. Maintaining a competitive operating cost structure and strong balance sheet while operating in an environmentally and socially responsible manner are integral to the implementation of our strategy.

Key Contractual Arrangements

In the ordinary course of operating our business, we enter into a number of key contracts for services that are critical with respect to our ability to develop, produce, store and bring our production to market. The following is a summary of our most significant contractual arrangements.

Drilling and Completion. From time to time we enter into drilling, completion and materials contracts in the ordinary course of business to ensure availability of rigs, frac crews and materials to satisfy our development program. As of December 31, 2021, there were no drilling, completion or materials agreements with terms that extended beyond one year.

Crude oil gathering and transportation service contracts. We have long-term agreements that provide us with field gathering and intermediate pipeline transportation services for a majority of our crude oil and condensate production in Lavaca and Gonzales Counties, Texas. We also have volume capacity support for certain downstream interstate pipeline transportation. The following table provides details on these contractual arrangements as of December 31, 2021:

Description of contractual arrangement	**Expiration of Contractual Arrangement**	**Minimum Volume Delivery (bbl/d)**	**Expiration of Minimum Volume Commitment**
Field gathering agreement	February 2041	8,000	February 2031
Intermediate pipeline transportation services	February 2026	8,000	February 2026
Volume capacity support	April 2026	8,000	April 2026

Each of these arrangements also contain an obligation to deliver the first 20,000 gross barrels of oil per day produced from Gonzales, Lavaca, Fayette and DeWitt Counties, Texas. For certain of our crude oil volumes gathered under the field gathering agreement, our rate includes an adjustment based on NYMEX WTI prices. As crude oil prices increase, up to a cap of $90 per bbl, the gathering rate escalates pursuant to the field gathering agreement.

Crude oil storage. Through February 2041, we have access to 180,000 barrels of crude oil storage as a component of the crude oil gathering agreement referenced above. In addition, we have access for up to a maximum of 340,000 barrels of tank capacity through April 2022, and month-to-month thereafter at several locations in the South Texas region with three vendors including up to approximately 70,000 barrels at the service provider's central delivery point facility, or CDP, in Lavaca County, Texas, up to 90,000 barrels with a downstream interstate pipeline at their facility in DeWitt County, Texas and up to 62,000 barrels with a marketing affiliate of the aforementioned downstream interstate pipeline within their system on a firm basis and an additional 120,000 barrels, if available, on a flexible basis. For additional information relating to crude oil storage see Note 14 to our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Crude terminal dedication. We have a long-term dedication of certain specific leases to a crude purchase and throughput terminal agreement through 2032. Under the agreement, we may transfer dedicated oil for delivery to a gulf coast terminal in Point Comfort, Texas or to alternate locations to third parties and in either case pay a terminal fee.

Natural gas service contracts. We have agreements that provide us with field gathering, compression and short-haul transportation services for our natural gas production and gas lift for our hydrocarbon production under various terms through 2039.

Natural gas processing contracts. We also have agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. Several agreements covering the majority of our wet gas production extend beyond three years, including one significant agreement that extends into 2029.

Major Customers

We sell a significant portion of our oil and gas production to a relatively small number of customers, as is typical in our industry. For the years ended December 31, 2021 and 2020, approximately 48% and 56%, respectively, of our consolidated product revenues were attributable to three customers, each of whom accounted for at least 10%. For the year ended December 31, 2019, approximately 76% of our consolidated product revenues were attributable to four customers, each of whom accounted for at least 10%. There were no other customers that individually accounted for more than 10% of our consolidated product revenues for the years ended December 31, 2021, 2020 and 2019.

Seasonality

Our sales volumes of crude oil and natural gas are dependent upon the number of producing wells and, therefore, are not seasonal by nature. We do not believe that the pricing of our crude oil and NGL production is subject to any meaningful seasonal effects. Historically, the pricing of natural gas is seasonal, typically with higher pricing in the winter months.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. Some of our competitors not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. Competition is particularly intense in the acquisition of prospective oil and gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We also compete with other oil and gas companies to secure drilling rigs, frac fleets, sand and other equipment and materials necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such materials, equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations that govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2021, we had $8.4 million of asset retirement obligations and environmental remediation liabilities assumed in the Lonestar Acquisition of $2.3 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general.

We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations or cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing or the ability to conduct oil and gas development could have the potential to adversely affect our financial condition, results of operations and cash flows. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation or enforcement of environmental laws and regulations and may thereby increase compliance costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

The following is a summary of the significant environmental laws to which our business operations are subject:

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the “Superfund” law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Such “responsible parties” may be subject to joint and several liability under CERCLA 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 the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of oil and gas for a number of years. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination. States also have environmental cleanup laws analogous to CERCLA, including Texas.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future and therefore be subject to more stringent regulation under RCRA. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term “waters of the United States” has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters, such as waters of the United States. The discharge of pollutants, including dredge or fill materials in regulated wetlands, into regulated waters or wetlands without a permit issued by the EPA, the U.S. Army Corps of Engineers, or the Corps, or the state is prohibited. The Clean Water Act has been interpreted by these agencies to apply broadly. The EPA and the Corps released a rule to revise the definition of “waters of the United States,” or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. However, the EPA rescinded this rule in 2019 and promulgated the Navigable Waters Protection Rule in 2020. The Navigable Waters Protection Rule defined what waters qualify as navigable waters of the United States and are under Clean Water Act jurisdiction. This new rule has generally been viewed as narrowing the scope of waters of the United States as compared to the 2015 rule, but litigation in multiple federal district courts is currently challenging the rescission of the 2015 rule and the promulgation of the Navigable Waters Protection Rule. In June 2021, the Biden Administration announced plans to develop its own definition for jurisdictional waters. On December 7, 2021, the Administration announced a proposed rule to revise the definition of “waters of the Untied States.” On January 24, 2022, the Supreme Court agreed to consider the scope of the Clean Water Act again in a new appeal, *Sackett v. EPA.*

The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In 2016, the EPA finalized new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Safe Drinking Water Act. The Safe Drinking Water Act, or the SDWA, and the Underground Injection Control Program promulgated under the SDWA, establish the requirements for salt water disposal well activities and prohibit the migration of fluid-containing contaminants into underground sources of drinking water. The Underground Injection Well Program requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells, and regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be, or determined to be, contributing to seismic activity, then TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that disposal well. TRC has used this authority to deny permits for waste disposal wells. The TRC has created Seismic Response Areas (“SRAs”) with action plans to address seismic activity, including the Gardendale SRA in September 2021, the North Culberson-Reeves SRA in October 2021 and the Stanton SRA in January 2022. The potential adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Eagle Ford formation, and is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. In addition, separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to induced seismicity. The EPA also released the results of its comprehensive research study to investigate the potential adverse impacts of hydraulic fracturing on drinking water and ground water in December 2016, finding that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. These developments could establish an additional level of regulation, including a removal of the exemption for hydraulic fracturing from the SDWA, and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercially feasible without the use of hydraulic fracturing.

Chemical Disclosures Related to Hydraulic Fracturing. Texas has implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. For example, Texas has water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or existing wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

On April 17, 2012, for example, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. Further, in May 2016, the EPA issued final NSPS governing methane emissions from the oil and gas industry as well as source determination standards for determining when oil and gas sources should be aggregated for CAA permitting and compliance purposes. However, in August 2020 the EPA rescinded methane and volatile organic compound emissions standards for new and modified oil and gas transmission and storage infrastructure, as well as methane limits for new and modified oil and gas production and processing equipment. The EPA also relaxed requirements for oil and gas operators to monitor emissions leaks. In President Biden's Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden directed the EPA to consider suspending, rescinding, or revising the Trump Administration's NSPS rule for the oil and gas sector. In November 2021, the EPA proposed new NSPS updates and emission guidelines to reduce methane and other pollutants from the oil and gas industry.

The U.S. Bureau of Land Management, or BLM, finalized its own rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM subsequently announced a revised rule which would scale back the waste-prevention requirements of the 2016 rule, but this revised rule was vacated by a California federal district court in 2020, a decision which BLM has appealed to the Ninth Circuit Court of Appeals. However, separately, the federal district court of Wyoming vacated the original 2016 rule in October 2020. These rules have required changes to our operations, including the installation of new equipment to control emissions. These rules would result in an increase to our operating costs and change to our operations. As a result of this continued regulatory focus, future federal and state regulations of the oil and gas industry remain a possibility and could result in increased compliance costs on our operations.

In November 2015, the EPA revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as non-attainment, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Generally, it will take the states several years to develop compliance plans for their non-attainment areas. While we are not able to determine the extent to which this new standard will impact our business at this time, it has the potential to have a material impact on our operations and cost structure.

In June 2016, the EPA finalized a rule "aggregating" individual wells and other facilities and their collective emissions for purposes of determining whether major source permitting requirements apply under the CAA. These changes may introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other GHGs, present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources.

Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of GHG emissions. Most recently in April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. In 2020, the Trump administration withdrew the United States from the Paris Agreement, but under the direction of President Biden, the United States rejoined the Paris Agreement in February 2021. Under the Paris Agreement, the Biden Administration has committed the U.S. to reducing its greenhouse gas emissions by 50 to 52% from 2005 levels by 2030. In November 2021, the U.S. and other countries entered into the Glasgow Climate Pact, which includes a range of measures designed to address climate change, including but not limited to the phase-out of fossil fuel subsidies, reducing methane emissions 30% by 2030, and cooperating toward the advancement of the development of clean energy.

In August 2015, the EPA issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this rule, nationwide carbon dioxide emissions would be reduced by approximately 30% from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of this rule pending judicial review. In August 2019, the EPA finalized the repeal of the 2015 regulations and replaced them with the Affordable Clean Energy rule, or ACE, that designates heat rate improvement, or efficiency improvement, as the best system of emissions reduction for carbon dioxide from existing coal-fired electric utility generating units. In 2021, the U.S. Court of Appeals for the District of Columbia struck down the ACE rule, but did not reinstate the former CPP regulation. The power of EPA to reissue the CPP under Section 111(d) of the CAA will be decided by the Supreme Court in 2022.

The EPA has issued the "Final Mandatory Reporting of Greenhouse Gases" Rule and a series of revisions to it, which requires operators of oil and gas production, natural gas processing, transmission, distribution and storage facilities and other stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. These rules do not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

In certain circumstances, large sources of GHG emissions are subject to preconstruction permitting under the EPA's Prevention of Significant Deterioration program. This program historically has had minimal applicability to the oil and gas production industry. However, there can be no assurance that our operations will avoid applicability of these or similar permitting requirements, which impose costs relating to emissions control systems and the efforts needed to obtain the permit.

Additional GHG regulations potentially affecting our industry include those described above under the subheading "Clean Air Act" which relate to methane.

Future federal GHG regulations of the oil and gas industry remain a possibility. Also, many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. Many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. While it is not possible to predict how any regulations to restrict GHG emissions may come into force, these and other legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or curtail oil and gas operations in certain areas and could also adversely affect demand for the oil and gas we sell.

President Biden and the Democrat Party, which currently controls Congress, have identified climate change as a priority, and it is likely that new executive orders, regulatory action, and/or legislation targeting greenhouse gas emissions, or prohibiting, delaying or restricting oil and gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. For example, the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee, and President Biden recently announced a moratorium on new oil and gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. President Biden's order also established climate change as a primary foreign policy and national security consideration, affirms that achieving net-zero greenhouse gas emissions by or before mid-century is a critical priority, affirms President Biden's desire to establish the United States as a leader in addressing climate change, generally further integrates climate change and environmental justice considerations into government agencies' decision making, and eliminates fossil fuel subsidies, among other measures.

Finally, scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the Endangered Species Act. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves. Similar protections are given to bald and golden eagles under the Bald and Golden Eagle Protection Act and to migratory birds under the Migratory Bird Treaty Act, and similar protections may be available to certain species protected under state laws.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment of the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of some of our oil and gas projects. For example, on January 27, 2022, the United States District Court for the District of Columbia found that the Bureau of Ocean Management's failure to calculate the potential emissions from foreign oil consumption violated the agency's approval of oil and gas leases in the Gulf of Mexico under the National Environmental Policy Act. This decision may disrupt or delay drilling operations if the agency is forced to reassess the environmental impacts of the Gulf of Mexico drilling program.

Natural Gas Pipeline Safety Act. On November 15, 2021, the Pipeline and Hazardous Materials Safety Administration promulgated a rule expanding the scope of the Federal Pipeline Safety Regulations to include all onshore gas gathering pipelines. For the first time, gas lines transporting natural gas from production facilities to interstate gas transmission lines will be subject to federal pipeline regulations and operators will be required to report safety information for all gas gathering lines. The rules become effective on May 16, 2022. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Human Capital

At Ranger Oil, employees are integral to the Company's success. Ranger Oil's key human capital management objectives are to attract, retain and develop talent to deliver on our strategy. As of December 31, 2021, we had a total of 136 employees, including 81 office-based employees and 55 field employees. All of these employees were full-time employees. None of our employees are represented by labor unions or covered by collective bargaining agreements. We focus on the following areas in supporting our human capital:

Diversity and Inclusion. We recognize that a diverse workforce provides the best opportunity to obtain unique perspectives, experiences and ideas to help our business succeed, and we are committed to providing a diverse and inclusive workplace to attract and retain talented employees. We maintain a work culture that treats all employees fairly and with respect, promotes inclusivity, and provides equal opportunities for the professional growth and advancement based on merit. Our Code of Business Conduct and Ethics prohibits discrimination on the basis of race, color, religion, national origin, sex, age (as defined by the law) or disability.

Health and Safety. Safety is a top priority at Ranger Oil. We promote safety with a robust health and safety program, which includes employee orientation and training, regular safety meetings, contractor management, risk assessments, hazard identification and mitigation, incident reporting and investigation, and corrective and preventative action development. Additionally, we have a Health, Safety and Environment Manual which includes specific field safety procedures, including responsibility to stop work on any activity deemed unsafe without the threat or fear of job reprisal.

Training and Development. We invest in developing our employees to enable us to realize opportunities for growth and contribute to advancing progress on our strategic priorities. Our ongoing efforts and initiatives are aimed at attracting, engaging, and developing employees in a thoughtful and meaningful way to support a diverse and inclusive culture. We encourage our employees to advance their knowledge and skills and to network with other professionals in order to pursue career advancement and enhance their skills.

Compensation and Benefits. We seek to provide fair, competitive compensation and comprehensive benefits to our employees that are designed to attract, retain and motivate employees. To align our short- and long-term objectives, our compensation programs consist of base pay, short-term incentives and long-term incentives, including restricted stock unit grants. Our wide array of benefits include medical, dental, and vision insurance plans for employees and their families, life insurance and long-term disability plans, paid time off for holidays, vacation, sick leave, and other personal leave, and health and dependent care savings accounts. We also provide our employees with a 401(k) plan that includes a competitive company match, and employees have access to several other programs, such as a matching charitable gift program.

COVID-19 Response. In response to the COVID-19 pandemic, we implemented proactive measures to protect the health and safety of our employees. These measures have included, at various times, implementation of health screenings, allowing remote work, requiring social distancing, requiring the use of masks, frequently and extensively disinfecting common areas, if and when necessary, and implementing isolation requirements, among other things. We are committed to maintaining a safe workplace to protect our employees.

Available Information

Our internet address is http://www.rangeroil.com. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter, Nominating and Governance Committee Charter and Reserves Committee Charter, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website 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 filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Investors can obtain current and important information about the company from our website on a regular basis. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we furnish or file with the SEC. We intend for our website to serve as a means of public dissemination of information for purposes of Regulation FD.

Item 1A. Risk Factors

Our business and operations are subject to a number of risks and uncertainties as described below; however, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition, results of operations and cash flows in the future. If any of the following risks actually occur, our business, financial condition, results of operations and cash flows could suffer and the trading price of our Class A Common Stock could decline.

Risks in this section are grouped by the following categories: (1) Risks Associated with our General Business; (2) Financial and Related Risks; (3) Legal and Regulatory Risks; (4) Tax-Related Risks; (5) Technology-Related Risks; and (6) Risks Related to the Ownership of Our Class A Common Stock. Many risks affect more than one category, and the risks are not in order of significance or probability of occurrence because they have been grouped by categories.

Risks Associated with our General Business

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control and strongly affect our financial condition, results of operations and cash flows.

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control, including:

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for crude oil, NGLs and natural gas;
- political and economic conditions in oil or gas producing regions;
- the extent to which the members of the Organization of Petroleum Exporting Countries and other oil exporting nations ("OPEC+") agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions;
- prices and availability of, and demand for, alternative fuels;
- the effect of energy conservation efforts, alternative fuel requirements and climate change-related initiatives;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil, natural gas and NGLs so as to minimize emissions of carbon dioxide and methane GHGs;
- volatility and trading patterns in the commodity-futures markets;
- technological advances or social attitudes and policies affecting energy consumption and energy supply;
- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which crude oil prices are benchmarked globally, against foreign currencies;
- changes in trade relations and policies, including the imposition of tariffs by the United States or China or sanctions related to the Russia-Ukraine conflict;
- risks related to the concentration of our operations in the Eagle Ford Shale field in South Texas;
- speculation by investors in oil and gas;
- the availability, cost, proximity and capacity of gathering, processing, refining and transportation facilities;
- the cost and availability of products and personnel needed for us to produce oil and gas;
- weather conditions;
- the impact and uncertainty of world health events, including the COVID-19 pandemic; and
- domestic and foreign governmental relations, regulation and taxation, including limits on the United States' ability to export crude oil.

For example, oil and natural gas prices continued to be volatile in 2021, as COVID-19 pandemic-related restrictions began to loosen and global economic activity grew, resulting in the demand for energy outpacing supply. The NYMEX oil prices in 2021 ranged from a high of $84.65 to a low of $47.62 per bbl, while the spot market prices for natural gas in 2021 ranged from a high of $23.61 (due to the February 2021 winter storm) to a low of $2.36 per MMBtu. Though oil prices have fully recovered, prices will continue to be influenced by the duration and severity of the COVID-19 pandemic and its resulting impact on oil and natural gas demand, the extent to which countries abide by the OPEC+ production agreement, the effects of the Russia-Ukraine conflict and U.S. production levels.

The long-term effects of these and other conditions on the prices of oil and natural gas are uncertain, and there can be no assurance that the demand or pricing for our products will follow historic patterns or that the recent pricing trend will continue. Any substantial or extended decline, or sustained market uncertainty, in the actual prices of crude oil, NGLs or natural gas would have a material adverse effect on our business, financial position, results of operations, cash flows and borrowing capacity, stock price, the quantities of oil and gas reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

It is impossible to predict future commodity price movements with certainty; however, many of our projections and estimates are based on assumptions as to the future prices of crude oil, NGLs and natural gas. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates.

Drilling and operations activities are high-risk activities with many uncertainties and may not result in commercially productive reserves.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Oil and gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and gas production. The costs of drilling, completing and operating wells are often substantial and uncertain, and drilling and completion operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including:

- unexpected drilling conditions;
- the use of multi-well pad drilling that requires the drilling of all of the wells on a pad until any one of the pad's wells can be brought into production;
- risks associated with drilling horizontal wells and extended lateral lengths, such as deviating from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- risks associated with downspacing and multi-well pad drilling;
- fracture stimulation accidents or failures;
- reductions in oil, natural gas and NGL prices;
- elevated pressure or irregularities in geologic formations;
- loss of title or other title related issues;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, frac fleets, crews, equipment and materials;
- shortages in experienced labor;
- crude oil, NGLs or natural gas gathering, transportation, processing, storage and export facility availability, restrictions or limitations;
- surface access restrictions;
- delays imposed by or resulting from compliance with regulatory requirements, including any hydraulic fracturing regulations and other applicable regulations, and the failure to secure or delays in securing necessary regulatory, contractual and third-party approvals and permits;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms;
- limitations in the market for crude oil, natural gas and NGLs;
- fires, explosions, blow-outs and surface cratering;
- adverse weather conditions; and
- actions by third-party operators of our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The type curves we use in our development plans are only estimates of performance of the acreage we might develop and actual production can differ materially. Furthermore, the cost of drilling, completing, equipping and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. In addition, limitations on the use of hydraulic fracturing could have an adverse effect on our ability to develop and produce oil and gas from new wells, which would reduce our rate of return on these wells and our cash flows. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, and we cannot be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business, financial condition, results of operations and cash flows. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or gas from all of them.

The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our business, financial position, results of operations and/or cash flows will depend on future developments, which are uncertain and cannot be predicted.

The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, and created significant volatility and disruption of financial and commodity markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, during the course of the pandemic, there have been significant reductions in demand for and prices of oil, NGLs and natural gas, which have at times adversely impacted, and may in the future adversely impact, our business, financial position, results of operations and cash flows. The COVID-19 pandemic has had an adverse impact on our operational and financial performance and its future impact is uncertain and depends on various factors, including how the pandemic and measures taken in response to the pandemic may impact demand for oil, NGLs and natural gas, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations. In particular, vaccine or testing mandates could be implemented in the future, which could result in disruptions to our workforce and may result in increased attrition, as well as increased costs in connection with retaining our workforce and implementation.

There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic adversely impacts our results will depend on future developments, which cannot be predicted with precision, including, but not limited to, the duration and spread of the outbreak (including the impact of coronavirus mutations and resurgences), its severity, the actions to contain the virus or treat its impact, the development, availability and public acceptance of effective treatments or vaccines, its impact on the U.S. and world economies, the U.S. capital markets and market conditions, the availability of federal, state, or local funding programs, and how quickly and to what extent normal economic and operating conditions can resume.

Our business involves many operating risks, including hydraulic fracturing, that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and gas, including well stimulation and completion activities such as hydraulic fracturing. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures or structures;
- pipeline ruptures or spills;
- mechanical difficulties, such as stuck oilfield drilling and service tools;
- uncontrollable flows of oil, natural gas or well fluids;
- migration of fracturing fluids into surrounding groundwater;
- spills or releases of fracturing fluids including from trucks sometimes used to deliver these materials;
- spills or releases of brine or other produced water that may go off-site;
- subsurface conditions that prevent us from (i) stimulating the planned number of stages, (ii) accessing the entirety of the wellbore with our tools during completion or (iii) removing all fracturing-related materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil or produced water spills and discharges of toxic gases; and
- natural disasters and other adverse weather conditions, such as named winter storms in 2021 and 2022 that caused us to temporarily shut-in production, (including events that may be caused or exacerbated by climate change);
- terrorism, vandalism and physical, electronic and cyber security breaches.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean up responsibilities, regulatory investigations and penalties, loss of well location, acreage, expected production and related reserves and suspension of operations. Moreover, a potential result of climate change is more frequent or more severe weather events or natural disasters. To the extent such weather events or natural disasters become more frequent or more severe, disruptions to our business and costs to repair damaged facilities could increase. To the extent such weather events or natural disasters become more frequent or severe, disruptions to our business and costs to repair damaged facilities could increase. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

If we experience any problems with well stimulation and completion activities, such as hydraulic fracturing, our ability to explore for and produce oil or natural gas may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of:

- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of GHGs;
- the need to shut down, abandon and relocate drilling operations;
- the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids;
- the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred; or
- suspension of our operations.

In accordance with industry practice, we maintain insurance at a level that balances the cost of insurance with our assessment of the risk and our ability to achieve a reasonable rate of return on our investments. We cannot assure you that our insurance will be adequate to cover losses or liabilities or that we will purchase insurance against all possible losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Multi-well pad drilling and project development may result in volatility in our operating results.

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing.

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the risk of unintentional communication with other adjacent wells and the potential to reduce total recoverable reserves from the reservoir. If these risks materialize and negatively impact our results of operations relative to guidance or market expectations, the research analysts who cover us may downgrade our Class A Common Stock or change their recommendations or earnings or performance estimates, which may result in a decline in the market price of our Class A Common Stock.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews, frac crews, and related equipment and material; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. There can be no assurance that these projects can be successfully developed or that any identified drill sites will, if drilled, encounter reservoirs of commercially productive oil or gas or that we will be able to complete such wells on a timely basis, or at all. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects wells within such project area.

Our business depends on gathering, processing, refining and transportation facilities owned by others.

We deliver substantially all of our oil and gas production through pipelines and trucks that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines and trucks, as well as gathering systems, gas processing facilities and downstream refineries. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells, the reduction in wellhead pricing or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather, process, refine and market our oil and gas.

We have entered into firm transportation contracts that require us to pay fixed sums of money regardless of quantities actually shipped. If we are unable to deliver the minimum quantities of production, such requirements could adversely affect our results of operations, financial position, and liquidity.

We have entered into firm transportation contracts that require us to pay fixed sums of money regardless of quantities actually shipped. If we are unable to deliver the minimum quantities of production, such requirements could adversely affect our results of operations, financial position, and liquidity. We have entered into firm transportation agreements for a portion of our production in certain areas in order to improve our ability, and that of our purchasers, to successfully market our production. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements. Additionally, these agreements obligate us to pay fees on minimum volumes regardless of actual throughput. If we have insufficient production to meet the minimum volumes, the requirements to pay for quantities not delivered could have an impact on our results of operations, financial position, and liquidity.

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

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion operations. The ability and availability of third-party service providers to perform such drilling and completion operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, NGLs and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations on a timely basis could delay drilling or completion operations, reduce production from the property or cause other damage to operations, each of which could adversely affect our business, financial condition, results of operations and cash flows.

Moreover, the oil and gas industry is cyclical, which can result in shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies and personnel, including geologists, geophysicists, engineers and other professionals. When shortages occur, the costs and delivery times of drilling rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig and frac crews also rise with increases in demand. The prevailing prices of crude oil, NGLs and natural gas also affect the cost of and the demand for drilling rigs, frac crews, materials (including sand) and other equipment and related services. The availability of drilling rigs, frac crews, materials (including sand) and equipment can vary significantly from region to region at any particular time. Although land drilling rigs and frac crews can be moved from one region to another in response to changes in levels of demand, an undersupply in any region may result in drilling and/or completion delays and higher well costs in that region.

We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third-party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs and frac crews at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations. As a result of the COVID-19 pandemic and recent industry downturn, many experienced service providers have left the industry and remaining personnel are more limited and in some cases, less experienced, which could impact success of our operations and have a safety impact.

The COVID-19 pandemic has also significantly disrupted global supply chains including with respect to certain materials necessary to our operations, tubulars and steel in particular, and the Russia-Ukraine conflict may have further disruptive effects or increase costs of these materials. If we are unable to timely source such materials in the future or if the prices of such materials increase, we may have to curtail or delay our operations and our results of operations and cash flows may be adversely impacted. Further, limited availability of materials may limit our ability to optimize our drilling and completions designs which could negatively impact our operations.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operating activities. We must make substantial capital expenditures to find, acquire, develop and produce new oil and gas reserves. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves with our cash flows from operating activities. Furthermore, external sources of capital may be limited.

The ability to attract and retain key members of management, qualified Board members and other key personnel is critical to the success of our business and may be challenging.

Our success will depend to a large extent upon the efforts and abilities of our management team and having experienced individuals serving on our Board who are also knowledgeable about our operations and our industry. The success of our business also depends on other key personnel. The ability to attract and retain these key personnel may be difficult in light of the volatility of our business. We may need to enter into retention or other arrangements that could be costly to maintain. These factors could cause us to incur greater costs or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do. If executives, directors or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them adequately or in a timely manner and we could experience significant declines in productivity.

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

Leases on oil and gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change and subject to the availability of capital.

Certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that they own.

The drilling and production of potential locations by us or other operators could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of our revenues. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly affect our overall credit risk. In 2021, approximately 48% of our total consolidated product revenues resulted from three of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest under joint venture arrangements. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one party. We could be held liable for joint venture obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the volatility in commodity prices increases the likelihood that some of these working interest owners may not be able to fulfill their joint venture obligations. Some of our project partners have experienced liquidity and cash flow problems in the past. These problems have led and may lead our partners to attempt to delay the pace of project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition, results of operations and cash flows.

Estimates of oil and gas reserves and future net cash flows are not precise, and undeveloped reserves may not ultimately be converted into proved producing reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various factors and assumptions, including assumptions relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, development costs and workover and remedial costs, the quantity, quality and interpretation of relevant data, taxes and availability of funds. The process of estimating oil and gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and inherently uncertain, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data, and improvements or other changes in geological, geophysical and engineering evaluation methods may cause reserve estimates to change over time. Any material inaccuracies in these reserve estimates, cash flow estimates or underlying assumptions could materially affect the estimated quantities and present value of our reserves.

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

At December 31, 2021 and December 31, 2020, approximately 62% and 60%, respectively, of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve data assumes that we can and will make these significant expenditures to develop our reserves and conduct these drilling operations successfully. These assumptions, however, may not prove correct, and our estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

The reserve estimation standards under SEC rules provide that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These standards may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame or cannot demonstrate that we could do so. Accordingly, our reserve report at December 31, 2021, includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $1.7 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. During the year ended December 31, 2021, we wrote-off 14.0 MMboe of proved undeveloped reserves because they are no longer expected to be developed within five years of their initial recording. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. Actual future net cash flows may also be affected by the amount and timing of actual production, availability of financing for capital expenditures necessary to develop our undeveloped reserves, supply and demand for oil and gas, increases or decreases in consumption of oil and gas and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. With all other factors held constant, if commodity prices used in the reserve report were to decrease by 10%, our standardized measure and PV-10 would have decreased to approximately $2.5 billion and $2.8 billion, respectively. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may record impairments on our oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower crude oil, NGL and natural gas prices may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all reserves within such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be significant enough to result in a write-down that would further decrease reported earnings.

The full cost method of accounting for oil and gas properties under GAAP requires that at the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated after tax discounted future net revenues from proved properties adjusted for costs excluded from amortization (the "Ceiling Test"). The estimated after tax discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. In addition to revisions to reserves and the impact of lower commodity prices, Ceiling Test write-downs may occur due to increases in estimated operating and development costs and other factors. During fiscal 2021, we recorded impairments of our oil and gas properties of $1.8 million.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our business strategy.

The oil and gas industry is capital intensive. We incur and expect to continue to incur substantial capital expenditures for the acquisition, exploration and development of oil and gas reserves. We incurred approximately $274.1 million in acquisition, exploration and development costs, including capitalized interest and capitalized labor during the year ended December 31, 2021. We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our credit agreement (as defined below). However, our cash flow from operations and access to capital are subject to a number of variables, including: (i) the volume of oil and gas we are able to produce from existing wells, (ii) our ability to transport our oil and gas to market, (iii) the prices at which our commodities are sold, (iv) the costs of producing oil and gas, (v) global credit and securities markets, (vi) the ability and willingness of lenders and investors to provide capital and the cost of the capital, (vii) our ability to acquire, locate and produce new reserves, (viii) the impact of potential changes in our credit ratings and (ix) our proved reserves. Additionally, a negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our Class A Common Stock. Additional borrowings under our credit agreement or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit agreements and the Indenture impose certain limitations on our ability to incur additional indebtedness. If we desire to issue additional debt securities other than as expressly permitted under such debt agreements, we will be required to seek the consents in accordance with the requirements of such debt agreements, which consent may be withheld at their discretion. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our business strategy, we may be required to curtail operations, which could adversely affect our financial condition, results of operations and cash flows.

Our property acquisitions carry significant risks.

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. In the event we do complete an acquisition, such as the recently completed acquisition of Lonestar Resources US Inc. and of certain oil and gas assets from Rocky Creek, its success will depend on a number of factors, many of which are beyond our control. These factors include, future crude oil, NGL and natural gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment, possible future environmental or other liabilities and the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and the assumption of potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties is costly and involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems, that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions. Further, we may not realize expected synergies. For instance, if we are unable to realize expected synergies from the Lonestar Acquisition, or the cost to achieve these synergies is greater than expected, then the anticipated benefits may not be realized fully or at all or may take longer to realize than expected. In addition, it is possible that the integration process of Lonestar could result in the loss of key employees, customers, providers, vendors or business partners, the disruption of our ongoing businesses, inconsistencies in standards, controls, procedures and policies, potential unknown liabilities and unforeseen expenses, delays, or regulatory conditions associated with higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated.

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

Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, or discover unknown liabilities after the acquisition, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the oil and gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations, financial condition and cash flows. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forgo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of oil and gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and gas leases can be generally lost and the target area can become undrillable. 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.

As a small company, we face unique difficulties competing in the larger market.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel, and we may face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and gas plays, to acquire new acreage, and to develop attractive oil and gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, greater access to capital, substantially larger staffs and greater financial and operating resources than we have. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our limited size has placed us at a disadvantage with respect to funding our capital and operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles (such as the volatility and general economic challenges attributable to COVID-19), are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development or production play can have a disproportionately negative impact on us. We also compete for people, including experienced geologists, geophysicists, engineers and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating primarily in one major contiguous area.

All of our operations are in the Eagle Ford Shale in South Texas, making us vulnerable to risks associated with operating in one geographic area. Due to the concentrated nature of our business activities, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that are more diversified. In particular, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, water shortages or other drought related conditions, plant closures for scheduled maintenance or interruption of transportation of crude oil or natural gas produced from wells in the Eagle Ford. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

Our oil, natural gas and NGLs are primarily sold in geographic markets in Texas which have a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, natural gas and/or NGLs, it could have a material negative effect on the prices we receive for our products and therefore an adverse effect on our financial condition and results of operations. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

Financial and Related Risks

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had $601.8 million of outstanding debt at March 4, 2022, including $193.0 million under the Credit Facility, $400.0 million, excluding unamortized discount and issuance costs, under the 9.25% Senior Notes due 2026 and other debt totaling $8.8 million.

Our indebtedness and any increase in our level of indebtedness could have adverse effects on our financial condition, results of operations and cash flows, including (i) imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities, (ii) increasing the risk that we may default on our debt obligations, (iii) increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business, (iv) increasing our exposure to a rise in interest rates, which will generate greater interest expense, (v) limiting our ability to engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes and (vi) limiting our flexibility in planning for or reacting to changes in our business and industry in which we operate. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are out of our control.

Additionally, we may incur substantially more debt in the future. Our Credit Facility and the Indenture contains restrictions that limit our ability to incur indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. If we were to incur additional indebtedness without retiring existing debt, the risks described above could be magnified.

The borrowing base under our credit facility may be reduced in the future if commodity prices decline.

As of December 31, 2021, the borrowing base under the Credit Facility was $725 million with aggregate elected commitments of $400 million. As of March 4, 2022, we had $193.0 million outstanding under the Credit Facility. Our borrowing base is generally redetermined at least twice each year and is scheduled to next be redetermined in April 2022. During a borrowing base redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. In the event of a decline in crude oil, NGL or natural gas prices or for other reasons deemed relevant by our lenders, the borrowing base under the Credit Facility may be reduced. Additionally, the lenders typically may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. As a result, we may be unable to obtain funding under the Credit Facility. If funding is not available when or in the amounts needed, or is available only on unfavorable terms, it might adversely affect our development plan and our ability to make new acquisitions. Furthermore, a determination to lower the borrowing base in the future to a level less than our outstanding indebtedness thereunder would require us to repay any indebtedness in excess of the redetermined borrowing base. Any such repayment or reduced access to funds could have a material adverse effect on our production, financial condition, results of operations and cash flows.

The Credit Facility and the Indenture have restrictive covenants that could limit our financial flexibility.

The Credit Facility and the Indenture contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including leverage, interest coverage and current ratios.

The Credit Facility and the Indenture include other restrictions that, among other things, limit our ability to incur indebtedness; grant liens; engage in mergers, consolidations and liquidations; make asset dispositions, restricted payments and investments; enter into transactions with affiliates; and amend, modify or prepay certain indebtedness.

Our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and gas prices at economically sustainable levels. If the price that we receive for our oil and gas production deteriorates significantly from current levels it could lead to lower revenues, cash flows and earnings, which in turn could lead to a default under certain financial covenants contained in our Credit Facility. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period as the amounts outstanding under our Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings. Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts. We may not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

Adverse changes in our credit rating may affect our borrowing capacity and borrowing terms.

Our outstanding debt is periodically rated by nationally recognized credit rating agencies. The credit ratings are based on our operating performance, liquidity and leverage ratios, overall financial position, and other factors viewed by the credit rating agencies as relevant to our industry and the economic outlook. Our credit rating may affect the amount of capital we can access, as well as the terms of any financing we may obtain. Because we rely in part on debt financing to fund growth, adverse changes in our credit rating may have a negative effect on our future growth.

Derivative transactions may limit our potential gains and involve other risks.

In order to achieve more predictable cash flows and manage our exposure to commodity price risks in the sale of our crude oil, NGLs and natural gas, we periodically enter into commodity price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of three years or less. While intended to reduce the effects of volatile crude oil, NGL and natural gas prices, such transactions may limit our potential gains if crude oil, NGL or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how commodity prices fluctuate in the future, which could have the effect of reducing our net income.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparty to a derivatives instrument fails to perform under the contract; or
- a sudden, unexpected event materially impacts commodity prices.

In addition, we may enter into derivative instruments that involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

The adoption of derivatives legislation and implementing rules could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC, to promulgate rules and regulations implementing the Dodd-Frank Act. While some of these rules have been finalized, some have not been finalized or implemented, and it is not possible at this time to predict when this will be accomplished. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however, this initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions, though these rules have not been finalized and the impact of those provisions on us is uncertain at this time.

While the CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing, and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules subjecting any other classes of swaps, including physical commodity swaps, to mandatory clearing. Although we believe we qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to be exempt from such requirements for the mandatory exchange of margin for uncleared swaps, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Further, if we did not qualify for an exemption and were required to post collateral for our swaps, it could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Dodd-Frank Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize and restructure our existing derivatives contracts and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, 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.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. The negative sentiment toward our sector versus other industry sectors has led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Such development could result in a reduction of available capital funding for potential development projects or diminution of capital to fund our business which could impact our future financial results. Additionally, such developments have resulted and could continue to result in downward pressure on the stock prices of oil and gas companies, including ours.

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 environmental, social and governance (“ESG”) matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Such ratings are used by some investors to inform their investment and voting decisions. Additionally, certain investors use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company’s sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of our stock from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of our operations by certain investors.

Legal and Regulatory Risks

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations, financial condition or cash flows. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations or other environmental, health or safety impacts, we may be charged with remedial costs and land owners may file claims for alternative water supplies, property damage or bodily injury. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Moreover, these risks are likely to be enhanced with the current U.S. presidential administration and Democrats controlling Congress. For example, see Part I, Item 1, "Business – Government Regulation and Environmental Matters – Greenhouse Gas Emissions" for information about certain actions the Biden Administration has taken targeting greenhouse gas emissions. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition, results of operations and cash flows. See Part I, Item 1, "Business – Government Regulation and Environmental Matters."

Access to water to drill and conduct hydraulic fracturing may not be available if water sources become scarce, and we may face difficulty disposing of produced water gathered from drilling and production activities.

The availability of water is crucial to conduct hydraulic fracturing. A significant amount of water is necessary for drilling and completing each well with hydraulic fracturing. In the past, Texas has experienced severe droughts that have limited the water supplies that are necessary to conduct hydraulic fracturing. Although we have taken measures to secure our water supply, we can make no assurances that sufficient water resources will be available in the short or long term to carry out our current activities. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and natural gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the RRC adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Climate change legislation, laws and regulations restricting emissions of greenhouse gases or prohibiting, restricting, or delaying oil and gas development on public lands, or legal or other action taken by public or private entities related to climate change could force us to incur increased capital and operating costs and could have a material adverse effect on our financial condition, results of operations and cash flows, as well as our reputation.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. For example, the EPA issued rules restricting methane emissions from hydraulically fractured and refractured gas wells, compressors, pneumatic controls, storage vessels, and natural gas processing plants. For more information on GHG regulation, see Part I, Item 1, "Business – Government Regulation and Environmental Matters."

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions. The adoption of legislation or regulatory programs or other government action to reduce emissions of GHGs or restrict, delay or prohibit oil and gas development on public lands could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements, or prevent us from conducting operations in certain areas. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. These risks are likely to be enhanced with the current U.S. presidential administration and Democrats controlling Congress. See Part I, Item 1, "Business – Government Regulation and Environmental Matters -Greenhouse Gas Emissions." Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, results of operations and cash flows. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves.

In addition, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If such climactic events were to occur more frequently or with greater intensity, our exploration and development activities and ability to transport our production to market could be adversely affected, as these events could cause a loss of production from temporary cessation of activity or damaged facilities and equipment. If any such events were to occur, they could have an adverse effect on our financial condition, results of operations and cash flows. For a more complete discussion of environmental laws and regulations intended to address climate change and their impact on our business and operations, see Part I, Item 1, "Business – Government Regulation and Environmental Matters."

There have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, as well as other stakeholders, promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital and adversely impact our reputation. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Federal state and local legislation 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 and adversely affect our production.

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and gas production. We routinely use hydraulic fracturing to complete wells. The EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of the EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but did not pass, legislation to amend the SDWA to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and gas companies in the hydraulic fracturing process. The EPA has issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. The EPA has also issued proposed and final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing; an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, a number of states and local regulatory authorities and federal politicians are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans/moratoria on drilling that effectively prohibit further production of oil and gas through the use of hydraulic fracturing or similar operations. Texas has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Moreover, the legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities, and the RRC has recently limited certain disposal well activity resulting from an increase in seismic events in certain areas of Texas. In light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, Texas regulators have asserted regulatory authority to limit injection activities in certain wells in an effort to reduce seismic activity. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil, natural gas and natural gas liquids activities utilizing injection wells for produced water disposal.

The adoption of new laws or regulations imposing reporting or operational obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations. These risks are likely to be enhanced with the current U.S. presidential administration and Democrats controlling Congress.

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

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

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

Like many oil and gas companies, from time to time, we expect to be involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of business. Such legal 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. 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.

Tax-Related Risks

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

Our ability to utilize U.S. net operating loss, or NOL, carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. As disclosed in Note 10 to our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data," we have substantial NOL carryforwards. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. As of December 31, 2021, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect. In addition, U.S. NOLs generated on or after January 1, 2018, can be limited to 80% of taxable income. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated. Additional state taxes on oil and gas extraction may be imposed, as a result of future legislation.

In recent years, lawmakers and Treasury have proposed certain significant changes to U.S. tax laws applicable to oil and gas companies. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and 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 any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes are ever made, as well as any similar changes in in U.S. federal tax law or state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our crude oil, NGLs and natural gas.

Technology-Related Risks

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, results of operations and cash flows could be adversely affected.

A cybersecurity incident could result in theft of confidential information, data corruption or operational disruption.

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development and production activities. Software programs are used for, among other things, reserve estimates, seismic interpretation, modeling and compliance reporting. In addition, the use of mobile communication is widespread. Increasingly, we must protect our business against potential cyber incidents including attacks as we have experienced and will continue to experience varying degrees of cyber incidents in the normal conduct of our business.

If our systems for protecting against cyber incidents prove insufficient, we could be adversely affected by unauthorized access to our digital systems which could result in theft of confidential information, data corruption or operational disruption. These cybersecurity threat actors are becoming more sophisticated and coordinated in their attempts to access a company's information technology systems and data, including the information technology systems of cloud providers and third parties with which a company conducts business. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;
- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- A cyber attack on third-party gathering, pipeline, or other transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market;
- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;
- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and
- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

Additionally, certain cyber incidents may remain undetected for an extended period. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows. Furthermore, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

Risks Related to the Ownership of Our Class A Common Stock

Juniper controls the Company, and their interests may conflict with the Company's and its shareholders' interests in the future.

Juniper beneficially owns approximately 51.7% of our Common Stock. As a result, Juniper is able to control the election and removal of our directors and thereby control our policies and operations and its interests may not in all cases be aligned with other shareholders' interests. In addition, Juniper may have an interest in pursuing acquisitions, divestitures and other transactions that, in its judgment, could enhance its investment, even though such transactions might involve risks to other shareholders. For example, Juniper could cause us to make acquisitions that increase our indebtedness or cause us to sell revenue-generating assets. Additionally, Juniper and its designated directors are not obligated to present any business opportunities (other than those presented to such directors in their roles as directors of the Company) to us.

In addition, Juniper is able to determine the outcome of many matters requiring shareholder approval and is able to cause or prevent a change of control of the Company or a change in the composition of our Board of Directors and could preclude any acquisition of the Company. This concentration of voting control could deprive shareholders of an opportunity to receive a premium for their shares of Class A Common Stock as part of a sale of the Company and ultimately might affect the market price of our Class A Common Stock.

Moreover, Juniper has certain director designation rights entitling them to designate up to five members of the Board out of a total of nine directors, with such designation rights being subject to certain step-downs.

We are a "controlled company" within the meaning of the Nasdaq rules and, as a result, expect to qualify for exemptions from certain corporate governance requirements.

Juniper controls a majority of the voting power of our Common Stock. As a result, we are a "controlled company" within the meaning of the corporate governance standards of Nasdaq. As a result, we are not required to comply with certain corporate governance requirements, including the requirement to have a majority of the board of directors be independent directors and the requirement to have compensation and nominating committees that are composed entirely of independent directors. While we have not elected to utilize these exemptions, in the future we could elect to do so. If we were to utilize any such exemptions, our shareholders would not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance rules for Nasdaq-listed companies.

Ranger Oil is a holding company. Ranger Oil's only material asset is its equity interest in the Partnership, and Ranger Oil is accordingly dependent upon distributions from the Partnership to pay taxes and cover its operating expenses and other obligations.

Following the Juniper Transactions, Ranger Oil is a holding company and has no material assets other than its equity interest in the Partnership. Ranger Oil has no independent means of generating revenue. To the extent the Partnership has available cash, Ranger Oil intends to cause the Partnership to make (i) pro rata distributions to its limited partners, including Ranger Oil, in an amount sufficient to allow Ranger Oil to pay its taxes and (ii) payments to Ranger Oil to cover its operating expenses and other obligations. To the extent that Ranger Oil needs funds and the Partnership or its subsidiaries are restricted from making such distributions or payments under applicable law or regulation or under the terms of any future financing arrangements, or are otherwise unable to provide such funds, Ranger Oil's liquidity and financial condition could be materially adversely affected.

Moreover, because Ranger Oil has no independent means of generating revenue, Ranger Oil's ability to pay dividends will be dependent on the ability of the Partnership to make cash distributions. This ability, in turn, may depend on the ability of the Partnership's subsidiaries to make distributions to it. The ability of the Partnership, its subsidiaries and other entities in which it directly or indirectly holds an equity interest to make such distributions will be subject to, among other things, (i) applicable laws or regulations that may limit the amount of funds available for distribution and (ii) restrictions in relevant debt instruments issued by the Partnership or its subsidiaries and other entities in which it directly or indirectly holds an equity interest.

In certain circumstances, the Partnership will be required to make tax distributions to its unitholders, including us, and the tax distributions that the Partnership will be required to make may be substantial.

Pursuant to the A&R Partnership Agreement, the Partnership will make generally pro rata cash distributions, or tax distributions, to its unitholders, including us, in an amount generally intended to allow the unitholders to satisfy their respective income tax liabilities with respect to their allocable share of the income of the Partnership, based on certain assumptions and conventions, provided that the distribution will be sufficient to allow us to satisfy our actual tax liabilities. Because tax distributions will be made pro rata based on ownership and based on an assumed tax rate, the Partnership could be required to make tax distributions that, in the aggregate, exceed the amount of taxes that the Partnership would have paid if it were taxed on its net income at its effective tax rate.

Funds used by the Partnership to satisfy its tax distribution obligations will not be available for reinvestment in the business. Moreover, the tax distributions the Partnership will be required to make may be substantial and may exceed the unitholder's tax liabilities if the unitholder has an overall effective tax rate that is lower than the assumed rate.

Certain provisions of our certificate of incorporation and our bylaws may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Articles of Incorporation and our Bylaws may have the effect of delaying or preventing changes in control if our Board determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Certificate of Incorporation and Bylaws include, among other things, those that:

- authorize our Board to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;
- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings; and
- limit the persons who may call special meetings of stockholders.

While these provisions have the effect of encouraging persons seeking to acquire control of the Company to negotiate with our Board, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors. These provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board, which is responsible for appointing the members of our management.

Our Articles of Incorporation designate the United States Direct Court for the Eastern District of Virginia or the federal district courts for the United States of America as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our shareholders, which could limit our shareholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.

Our Articles of Incorporation provide that, to the fullest extent required by law, the United States District Court for the Eastern District of Virginia, (or, if United States District Court for the Eastern District of Virginia lacks subject matter jurisdiction, another state or federal court located within the Commonwealth of Virginia) is the sole and exclusive forum for (i) any derivative action or proceeding brought on behalf of the Company, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of the Company to the Company or the Company's shareholders, (iii) any action asserting a claim arising pursuant to any provision of the Virginia Stock Corporation Act or (iv) any action asserting a claim governed by the internal affairs doctrine. Furthermore, under our Articles of Incorporation, the federal district courts for the United States of America are the sole and exclusive forum for causes of action arising under the Securities Act.

Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our shareholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision 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, prospects, or results of operations.

The market price of our Class A Common Stock is subject to volatility.

The market price of our Class A Common Stock could be subject to wide fluctuations in response to, and the level of trading of our Class A Common Stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our limited trading volume, the concentration of holdings of our Class A Common Stock, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this report. Significant sales of our Class A Common Stock, or the expectation of these sales, by significant shareholders, officers or directors could materially and adversely affect the market price of our Class A Common Stock.

Our business and the trading prices of our securities could be negatively affected as a result of actions of so-called "activist" shareholders, and such activism could impact the trading value of our securities.

Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. If we become the subject of activity by activist shareholders, responding to such actions could be costly and time-consuming, diverting the attention of our management and employees. Furthermore, activist campaigns can create perceived uncertainties as to our future direction, strategy, or leadership and may result in the loss of potential business opportunities and cause our stock price to experience periods of volatility.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market, or the perception that these sales could occur, could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

As of March 4, 2022, Juniper beneficially owned 22,548,998 shares of our Class B common stock, par value of $0.01 per share ("Class B Common Stock") and 22,548,998 common units in our Up-C partnership subsidiary, which are redeemable or exchangeable for 22,548,998 shares of our Class A Common Stock at the election of the holder for no additional consideration. Juniper may decide to reduce its investment in the Company at any time. Pursuant to the Investor and Registration Rights Agreement with Juniper, at their election, we are required to assist them in a secondary offering of the sale of their securities. Any such sales of Class A Common Stock by Juniper, or expectations thereof, could have the effect of depressing the market price for our Class A Common Stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2021, our oil and gas assets were located in the Brazos, Dewitt, Dimmit, Fayette, Frio, Gonzales, La Salle, Lavaca, and Robertson counties in South Texas.

Facilities

Our corporate headquarters and field office facilities are leased and we believe that they are adequate for our current needs.

Title to Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we review title opinions on all material leases. As is customary in the oil and gas industry; however, we make a cursory review of title when we acquire farmout acreage or undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are unable to cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Our oil and gas properties are subject to customary royalty interests, liens for debt obligations, current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties. We believe that we have satisfactory title to all of our properties and the associated oil and gas in accordance with standards generally accepted in the oil and gas industry.

Summary of Oil and Gas Reserves

Proved Reserves

The following tables summarize certain information regarding our estimated proved reserves as of December 31 for each of the years presented:

	Crude Oil (MMbbl)	NGLs (MMbbl)	Natural Gas (Bcf)	Oil Equivalents (MMboe)	Standardized Measure $ in millions	PV10 [1] $ in millions
2021						
Developed						
Producing	59.9	16.4	94.0	92.0		
Non-producing	0.1	—	—	0.1		
	60.0	16.4	94.0	92.1		
Undeveloped	103.1	23.6	131.2	148.6		
	163.1	40.0	225.2	240.7	$ 3,057.2	$ 3,418.7
Price measurement used	$66.57/bbl	$22.99/bbl	$3.60/MMBtu			
2020						
Developed						
Producing	36.4	8.0	37.6	50.6		
Non-producing	—	—	—	—		
	36.4	8.0	37.6	50.6		
Undeveloped	62.1	7.6	36.1	75.8		
	98.5	15.6	73.7	126.4	$ 650.3	$ 657.5
Price measurement used	$39.54/bbl	$7.51/bbl	$1.99/MMBtu			
2019						
Developed						
Producing	40.1	8.7	41.0	55.6		
Non-producing	0.5	0.2	0.8	0.8		
	40.6	8.9	41.8	56.4		
Undeveloped	58.3	10.3	48.6	76.7		
	98.9	19.2	90.4	133.1	$ 1,488.9	$ 1,600.1
Price measurement used	$55.67/bbl	$13.36/bbl	$2.58/MMBtu			

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[1] PV10 represents a non-GAAP measure that is most directly comparable to the Standardized Measure as defined in GAAP. The Standardized Measure represents the discounted future net cash flows from our proved reserves after future income taxes discounted at 10% in accordance with SEC criteria. PV10 represents the Standardized Measure without regard to income taxes of $361.5 million, $7.2 million and $111.2 million for 2021, 2020 and 2019, respectively. We believe that PV10 is a meaningful supplemental disclosure to the Standardized Measure as the PV10 concept is widely used within the industry and by the financial and investment community to evaluate the proved reserves on a comparable basis across companies without regard to the individual owner's unique income tax position. We utilize PV10 to evaluate the potential return on investment in our oil and gas properties as well as evaluating properties for potential purchases and sales.

A discussion and analysis of the changes in our total proved reserves and price measurements used is provided in "Supplemental Information on Oil and Gas Producing Activities (Unaudited)" included in Part II, Item 8, "Financial Statements and Supplementary Data."

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2021:

	Crude Oil (MMbbl)	**NGLs (MMbbl)**	**Natural Gas (Bcf)**	**Oil Equivalents (MMboe)**
Proved undeveloped reserves at beginning of year	62.1	7.6	36.1	75.8
Revisions of previous estimates	(5.6)	(1.3)	(6.0)	(8.0)
Extensions and discoveries	40.3	8.3	40.0	55.3
Purchase of reserves	16.2	10.2	66.6	37.5
Conversion to proved developed reserves	(9.9)	(1.2)	(5.5)	(12.0)
Proved undeveloped reserves at end of year	103.1	23.6	131.2	148.6

In 2021, our proved undeveloped reserves increased by 72.8 MMboe due primarily to the Juniper transactions and the Lonestar Acquisition increasing our reserves. Additionally, we optimized and refreshed the existing drilling inventory to access stranded acreage and optimize for longer laterals, resulting in an increase in average treatable lateral per well, thus increasing the average reserves per well. This process resulted in an increase to extensions and discoveries of 55.3 MMboe that was slightly offset by 14.0 MMboe of negative revisions due primarily to certain wells that are now beyond our five-year drilling window schedule. In addition, our revision of previous estimates reflect: (i) favorable revisions of 6.0 MMboe attributable to changes in lateral lengths and type curves, (ii) transferred out of undeveloped to proved developed 12.0 MMboe due to the 2021 drilling program.

During 2021, we incurred capital expenditures of $131.7 million attributable to drilling and completing 30 gross (25.8 net) wells in connection with the conversion of proved undeveloped reserves to proved developed reserves. Our conversion rates for quantities of proved undeveloped reserves were 16%, 12% and 22% in 2021, 2020 and 2019, respectively. The conversion rate decline experienced in 2020 was adversely impacted by the temporary suspension of our drilling and completion program from April through September of 2020 in response to the economic downturn associated with the global COVID-19 pandemic.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by DeGolyer and MacNaughton, Inc., our independent third party petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see “Supplemental Information on Oil and Gas Producing Activities (Unaudited)” in our notes to the consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data” and the report of DeGolyer and MacNaughton, Inc., dated February 7, 2022, which is included as an Exhibit to this Annual Report on Form 10-K.

Our policies and practices regarding the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC’s regulations and GAAP. Our Senior Vice President, Development is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. Our Senior Vice President and Chief Operating Officer has over 25 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from the Colorado School of Mines and is registered by the States of Colorado and Wyoming as a Petroleum Engineer. Our internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation. In addition to conducting these internal reviews and external reserves audits, we also have a Reserves Committee that consists of four members of our Board of Directors. This committee provides additional oversight of our reserves estimation and certification process.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Part I, Item 1A, “Risk Factors.”

Qualifications of Third Party Petroleum Engineers

The technical person primarily responsible for review of our reserve estimates at DeGolyer and MacNaughton, Inc. meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Oil and Gas Production, Production Prices and Production Costs

Production Prices and Production Costs

The following table sets forth the average sales prices per unit of volume and our average production costs, not including ad valorem and production/severance taxes, per unit of sales volume for the periods presented:

	Year Ended December 31, 2021	2020	2019
Sales volume:			
Crude oil (Mbbl)	7,711	6,829	7,453
NGLs (Mbbl)	1,326	1,165	1,491
Natural gas (MMcf)	6,712	5,360	7,067
Total (Mboe)	10,155	8,887	10,121
Average prices:			
Crude oil ($/bbl)	$ 67.09	$ 36.86	$ 58.33
NGLs ($/bbl)	$ 25.23	$ 7.68	$ 11.13
Natural gas ($/Mcf)	$ 3.89	$ 1.88	$ 2.51
Aggregate ($/boe)	$ 56.80	$ 30.47	$ 46.34
Average production and lifting cost ($/boe):			
Lease operating	$ 4.47	$ 4.22	$ 4.26
Gathering processing and transportation	2.33	2.48	2.29
	$ 6.80	$ 6.70	$ 6.55

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development wells that we completed and turned in line (regardless of when drilling was initiated), all of which were in the Eagle Ford in South Texas, during the years indicated and wells that were in progress at the end of each year. There were no exploratory wells drilled in any of the years presented.

	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	46	40.4	23	20.6	48	43.3
Dry hole	—	—	—	—	—	—
Total	46	40.4	23	20.6	48	43.3
Wells in progress at end of year [1]	12	10.4	7	6.3	8	7.3

[1] Includes 2 gross (1.9 net) wells completing, 3 gross (2.4 net) wells waiting on completion and 7 gross (6.1 net) wells being drilled as of December 31, 2021.

Present Activities

As of March 4, 2022, 3 gross (1.4 net) wells were completing and 7 gross (5.2 net) wells were in progress.

Delivery Commitments

We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts. We have commitments to provide minimum deliveries of crude oil of 8,000 gross barrels of oil per day through 2031 under gathering and transportation agreements with Nuevo Dos Gathering and Transportation, LLC and Nuevo Dos Marketing LLC. Our production and reserves are currently sufficient to fulfill the current 8,000 barrels of oil per day delivery commitment under these agreements. See Note 14 to our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information related to these commitments.

Productive Wells

The following table sets forth our productive wells in which we had a working interest as of December 31, 2021:

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	794	663.1	66	61.4	860	724.5

Of the total wells presented in the table above, we are the operator of 820 gross (755 oil and 65 natural gas) and 718.2 net (657.3 oil and 60.9 natural gas) wells. In addition to the above working interest wells, we own overriding royalty interests in 29 gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2021 (in thousands):

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Total acreage	99.4	81.4	72.6	59.5	172.0	140.9

The primary terms of our leases generally range from three to five years, and we do not have any concessions. As of December 31, 2021, our net undeveloped acreage is scheduled to expire as shown in the table below, unless the primary lease terms are, where appropriate, extended, HBP or otherwise changed (in thousands):

	2022	2023	2024	Thereafter
Expirations by year	4.2	3.8	0.8	—

We anticipate paying options to extend a substantial portion of the acreage scheduled to expire in 2022. We do not believe that the remaining scheduled expirations of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3. Legal Proceedings

See Note 14 to our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data." We are not aware of any material legal or governmental proceedings against us, or threatened to be brought against us, under the various environmental protection statutes to which we are subject.

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

Market Information

From December 28, 2016 through October 18, 2021, our common stock was listed and traded on the Nasdaq under the symbol “PVAC.” Following the completion of the Lonestar Acquisition, we changed our name from Penn Virginia Corporation to Ranger Oil Corporation and our Class A Common Stock began trading under the symbol “ROCC” on October 18, 2021.

Equity Holders

As of March 4, 2022, there were 248 record holders of our Class A Common Stock and two record holders of our Class B Common Stock. There is no public market for our Class B Common Stock.

Dividends

We have not paid any cash dividends on our common stock to date. However, in March 2022, we announced an intention to commence a quarterly dividend on our Class A Common Stock in the third quarter of 2022. Each Common Unit in the Partnership would be entitled to a distribution in the same amount of any dividend paid on the Class A Common Stock. We expect to fund all such dividends with cash flows from operations. There can be no assurance we will commence such dividends or pay dividends on a regular basis. Furthermore, we are limited in our ability to pay dividends under the Credit Facility and the Indenture.

Securities Authorized for Issuance Under Equity Compensation Plans

See Part III, Item 12, “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” and Note 16 to our consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data” for information regarding shares of common stock authorized for issuance under our stock compensation plans.

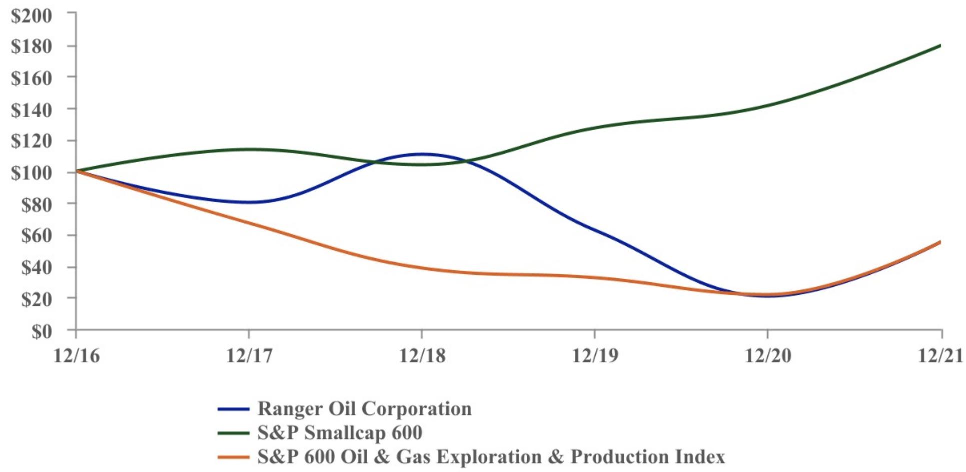
Issuer Purchases of Equity Securities

We did not repurchase any shares of our common stock in the fourth quarter of 2021.

Performance Graph

The following graph compares our cumulative total shareholder return with the cumulative total return of the Standard & Poor’s 600 Oil & Gas Exploration and Production Index and the Standard & Poor’s SmallCap 600 Index for the period from December 31, 2016 through December 31, 2021. The graph assumes that the value of the investment in our common stock, in each index, and in the peer group (including reinvestment of dividends) was $100 on December 31, 2016 and tracks it through December 31, 2021.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Ranger Oil Corporation, the S&P Smallcap 600 Index,
and S&P 600 Oil & Gas Exploration & Production Index



*$100 invested on 12/31/16 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

Item 6. [Reserved]

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto included in Part II, Item 8, "Financial Statements and Supplementary Data." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure, the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables. Certain amounts for the prior period have been reclassified to conform to the current period presentation.

This section of the Form 10-K discusses the results of operations for the year ended December 31, 2021 compared to the year ended December 31, 2020. The results of operations of Lonestar are reflected in our accompanying consolidated financial statements from the closing date of the Lonestar Acquisition through December 31, 2021. Results for the periods prior to October 5, 2021 reflect the financial and operating results of Ranger Oil and do not include the financial and operating results of Lonestar. As such, our historical results of operations are not comparable from period to period and may not be comparable to our financial results of operations in future periods. The results of operations for the year ended December 31, 2020 compared to the year ended December 31, 2019 that are not included in this Form 10-K are included in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Overview and Executive Summary

We are an independent oil and gas company focused on the onshore development and production of crude oil, NGLs, and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale in South Texas.

Key Developments in 2021

Acquisition of Lonestar Resources

On October 5, 2021, the Company acquired Lonestar Resources US Inc., a Delaware corporation ("Lonestar"), as a result of which Lonestar and its subsidiaries became wholly-owned subsidiaries of Ranger Oil (the "Lonestar Acquisition"). Lonestar's oil and gas properties are located in the Eagle Ford Shale in South Texas.

In accordance with the terms of the Lonestar Acquisition, Lonestar shareholders received 0.51 shares of our common stock for each share of Lonestar common stock held immediately prior to the effective time of the Lonestar Acquisition. Based on the closing price of our common stock on October 5, 2021 of $30.19, the total value of our common stock issued to holders of Lonestar common stock, warrants and restricted stock units as applicable, was approximately $173.6 million.

Following the completion of the Lonestar Acquisition, the Company changed its name from Penn Virginia to Ranger Oil Corporation, and its Class A Common Stock began trading on the Nasdaq under the ticker symbol "ROCC" on October 18, 2021. See Note 4 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information.

Financing and Hedging Updates

9.25% Senior Notes and Debt Repayments

On August 10, 2021, our indirect, wholly-owned subsidiary Penn Virginia Escrow LLC (the "Escrow Issuer") completed an offering of $400 million aggregate principal amount of senior unsecured notes due 2026 (the "9.25% Senior Notes due 2026"). These notes bear interest at 9.25% and were sold at 99.018% of par. Upon the closing of the Lonestar Acquisition, Penn Virginia Holdings, LLC ("Holdings") assumed all obligations under the 9.25% Senior Notes due 2026 and the net proceeds and certain other funds were released from escrow and used to repay and discharge $249.8 million of Lonestar's long-term debt including accrued interest and related expenses, and the remainder, along with cash on hand, of $146.2 million was used to repay the Second Lien Term Loan (the "Second Lien Term Loan") including a prepayment premium, accrued interest and related expenses. Obligations under the 9.25% Senior Notes due 2026 are guaranteed by the subsidiaries of Holdings that guarantee our revolving credit facility (the "Credit Facility").

Increased Borrowing Base of Credit Facility

Upon closing of the Lonestar Acquisition, our borrowing base under the Credit Facility increased to $600 million with aggregate elected commitments of $400 million. Effective December 31, 2021 the borrowing base was further increased to $725 million, with aggregate elected commitments remaining at $400 million.

See Note 9 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information on our debt.

Hedging Updates

Immediately following the Lonestar Acquisition, we paid approximately $50 million to restructure certain of Lonestar's derivatives, which was funded by borrowings under our Credit Facility. We reset the majority of the swaps to reflect market pricing at the time. See "– Commodity Hedging Program."

Recapitalization of the Company's Common Stock

On October 6, 2021, the Company effected a recapitalization (the "Recapitalization"), pursuant to which (i) the Company's common stock was renamed and reclassified as Class A Common Stock, (ii) the authorized number of shares of capital stock of the Company was increased to 145,000,000 shares, (iii) 30,000,000 shares of Class B Common Stock, a new class of capital stock of the Company, was authorized, (iv) all outstanding shares of the Series A Preferred Stock ("Series A Preferred Stock") were exchanged for newly issued shares of Class B Common Stock, and (v) the designation of the Series A Preferred Stock was cancelled.

See Note 15 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information.

Strategic Investment by Juniper

In January 2021, we consummated the Juniper Transactions whereby affiliates of Juniper contributed $150 million in cash and certain oil and gas assets in Lavaca and Fayette Counties in Texas to us in exchange for equity that entitles Juniper to both vote and share in any dividend on the same basis as 22,548,998 shares of Class A Common Stock (after post-closing adjustments). For additional information regarding the Juniper Transactions, see Note 4 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Industry Environment and Recent Operating and Financial Highlights

Commodity Price and Other Economic Conditions

As an oil and gas development and production company, we are exposed to a number of risks and uncertainties that are inherent to our industry. In addition to such industry-specific risks, the global public health crisis associated with COVID-19 continues to create uncertainty for global economic activity. Beginning in March 2020, the slowdown in global economic activity attributable to COVID-19 resulted in a dramatic decline in the demand for energy, which directly impacted our industry and the Company. Over the past year, however, increased mobility, deployment of vaccines and other factors has resulted in increased oil demand and commodity prices.

A high level of uncertainty remains regarding the volatility of energy supply and demand as OPEC+ continued to execute its strategy throughout 2021 to gradually increase production. In its most recent March 2022 meeting, OPEC+ reconfirmed the agreement to increase output for the month of April 2022 by 400,000 bbls/day. Most recently, WTI crude oil prices have jumped to over $120/bbl as a result of the Russia-Ukraine conflict and related sanctions. Higher energy prices, along with the global supply chain issues and other factors, have increased inflationary pressures, which has led or may lead to increased costs of services and certain materials necessary for our operations.

Our crude oil production is sold at a premium or deduct differential to the prevailing NYMEX West Texas Intermediate ("NYMEX WTI") price. The differential reflects adjustments for location, quality and transportation and gathering costs, as applicable. In 2021, we sold all of our crude oil volumes under Magellan East Houston ("MEH") pricing, whereas historically our crude oil volumes sold were largely priced using either Light Louisiana Sweet ("LLS"), or MEH grade differentials. While both LLS and MEH have historically been at a premium to NYMEX WTI, LLS has had a more favorable differential than MEH.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity, and supply and demand relationships in that region or locality. Similar to crude oil, our natural gas production price has a premium or deduct differential to the prevailing NYMEX Henry Hub ("NYMEX HH") price primarily due to differential adjustments for the location and the energy content of the natural gas. Location differentials result from variances in natural gas transportation costs based on the proximity of the natural gas to its major consuming markets that correspond with the ultimate delivery point as well as individual interaction of supply and demand.

A summary of these pricing differentials is provided in the discussion of "Results of Operations – Realized Differentials" that follows.

In addition to the volatility of commodity prices, we are subject to inflationary and other factors that have resulted in higher costs for products, materials and services that we utilize in both our capital projects and with respect to our operating expenses. In 2021, we took certain actions with vendors and other service providers to secure products and services at fixed prices and to pay for certain materials and services in advance in order to lock in favorable costs but we have continued to experience higher costs and this may be exacerbated in the future.

Capital Expenditures, Development Progress and Production

We currently operate two drilling rigs and during the year ended December 31, 2021, incurred capital expenditures of approximately $266.5 million, substantially all of which was directed to drilling and completion projects. During the fourth quarter 2021, a total of 12 gross (10.4 net) wells were completed and turned in line. As of March 4, 2022, we turned an additional 8 gross (6.7 net) wells in line and 3 gross (1.4 net) wells were completing and 7 gross (5.2 net) wells were in progress.

As of March 4, 2022, we had approximately 170,900 gross (139,900 net) acres in the Eagle Ford Shale, of which approximately 95% held by production and substantially all is operated by us.

Total sales volume for the fourth quarter 2021 was 3,702 Mboe, or 40,236 boe/d, with approximately 68%, or 2,532 Mbbls, of sales volume from crude oil, 17% from NGLs and 15% from natural gas.

Commodity Hedging Program

As of March 4, 2022, we have hedged a portion of our estimated future crude oil and natural gas production through the second quarter of 2024. The following table, inclusive of January and February 2022 production months, summarizes our hedge positions for the periods presented:

	1Q2022	2Q2022	3Q2022	4Q2022	1Q2023	2Q2023	3Q2023	4Q2023	1Q2024	2Q2024
NYMEX WTI Crude Swaps										
Average Volume Per Day (bbl)	3,806	3,000	3,000	3,000	2,500	2,400	2,807	2,657	462	462
Weighted Average Swap Price ($/bbl)	$ 76.35	$ 74.12	$ 73.01	$ 69.20	$ 54.40	$ 54.26	$ 54.92	$ 54.93	$ 58.75	$ 58.75
NYMEX WTI Crude Collars										
Average Volume Per Day (bbl)	18,750	17,720	12,636	9,375	6,250	6,181	1,630	1,630		
Weighted Average Purchased Put Price ($/bbl)	$ 58.39	$ 59.12	$ 54.84	$ 52.17	$ 50.67	$ 50.67	$ 60.00	$ 60.00		
Weighted Average Sold Call Price ($/bbl)	$ 72.75	$ 77.01	$ 73.83	$ 67.57	$ 65.65	$ 65.65	$ 76.12	$ 76.12		
NYMEX WTI Purchased Puts [1]										
Average Volume Per Day (bbl)	12,778									
Weighted Average Purchased Put Price ($/bbl)	$ 73.37									
NYMEX WTI Crude CMA Roll Basis Swaps										
Average Volume Per Day (bbl)	14,444	20,879	14,674	14,674						
Weighted Average Swap Price ($/bbl)	$ 0.898	$ 1.120	$ 1.172	$ 1.172						
NYMEX HH Swaps										
Average Volume Per Day (MMBtu)	17,500	12,500	12,500	12,500	10,000	7,500				
Weighted Average Swap Price ($/MMBtu)	$ 4.349	$ 3.727	$ 3.745	$ 3.793	$ 3.620	$ 3.690				
NYMEX HH Collars										
Average Volume Per Day (MMBtu)	3,333	13,187	13,043	13,043		11,538	11,413	11,413	11,538	11,538
Weighted Average Purchased Put Price ($/MMBtu)	$ 4.150	$ 2.500	$ 2.500	$ 2.500		$ 2.500	$ 2.500	$ 2.500	$ 2.500	$ 2.328
Weighted Average Sold Call Price ($/MMBtu)	$ 5.750	$ 3.220	$ 3.220	$ 3.220		$ 2.682	$ 2.682	$ 2.682	$ 3.650	$ 3.000
OPIS Mt Belv Ethane Swaps										
Average Volume per Day (gal)		28,022	27,717	27,717		98,901	34,239	34,239	34,615	
Weighted Average Fixed Price ($/gal)		$ 0.2500	$ 0.2500	$ 0.2500		$ 0.2288	$ 0.2275	$ 0.2275	$ 0.2275	

[1] 1Q2022 NYMEX WTI Purchased Puts comprised of 850,000 bbls in January 2022 at an average price of $65.47/bbl and 300,000 bbls in March 2022 at an average price of $95.00/bbl.

Results of Operations

The following table sets forth certain historical summary operating and financial statistics for the periods presented:

(in thousands except per unit measurements, sales volume, wells and reserves)	Three Months Ended			Year Ended December 31,	
	December 31, 2021	September 30, 2021	December 31, 2020	2021	2020
Total sales volume (Mboe) [1]	3,702	2,344	1,978	10,155	8,887
Average daily sales volume (boe/d) [1]	40,236	25,483	21,502	27,822	24,281
Crude oil sales volume (Mbbl) [1]	2,532	1,879	1,538	7,711	6,829
Crude oil sold as a percent of total [1]	68 %	80 %	78 %	76 %	77 %
Product revenues	$ 224,594	$ 140,133	$ 66,491	$ 576,824	$ 270,792
Crude oil revenues	$ 191,079	$ 127,995	$ 61,009	$ 517,301	$ 251,741
Crude oil revenues as a percent of total	85 %	91 %	92 %	90 %	93 %
Realized prices:					
Crude oil ($/bbl)	$ 75.48	$ 68.10	$ 39.66	$ 67.09	$ 36.86
NGLs ($/bbl)	$ 29.91	$ 27.24	$ 10.71	$ 25.23	$ 7.68
Natural gas ($/Mcf)	$ 4.54	$ 4.11	$ 2.45	$ 3.89	$ 1.88
Aggregate ($/boe)	$ 60.67	$ 59.77	$ 33.61	$ 56.80	$ 30.47
Realized prices, including effects of derivatives, net [2]					
Crude oil ($/bbl)	$ 64.50	$ 57.15	$ 48.84	$ 56.15	$ 50.55
NGLs ($/bbl)	$ 29.91	$ 25.77	$ 10.71	$ 24.86	$ 7.68
Natural gas ($/Mcf)	$ 2.99	$ 3.44	$ 1.95	$ 3.01	$ 1.88
Aggregate ($/boe)	$ 51.77	$ 50.49	$ 40.46	$ 47.87	$ 40.98
Production and lifting costs:					
Lease operating ($/boe)	$ 4.38	$ 4.54	$ 4.83	$ 4.47	$ 4.22
Gathering, processing and transportation ($/boe)	$ 2.19	$ 2.43	$ 2.66	$ 2.33	$ 2.48
Production and ad valorem taxes ($/boe)	$ 3.05	$ 3.21	$ 1.75	$ 3.06	$ 1.87
General and administrative ($/boe) [3]	$ 9.57	$ 4.66	$ 5.05	$ 6.55	$ 3.80
Depreciation, depletion and amortization ($/boe)	$ 12.97	$ 13.21	$ 13.03	$ 12.96	$ 15.83

[1] All volumetric statistics presented above represent volumes of commodity production that were sold during the periods presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

[2] Realized prices, including effects of derivatives, net is a non-GAAP measure (see discussion and reconciliation to GAAP measure below in "*Results of Operations – Effects of Derivatives*" that follows).

[3] Includes combined amounts of $7.57, $1.56, and $1.93 per boe for the three months ended December 31, 2021, September 30, 2021, and December 31, 2020, respectively, and $3.92 and $1.09 per boe for the years ended December 31, 2021 and 2020, respectively, attributable to share-based compensation and significant special charges, comprised of organizational restructuring and acquisition, divestiture and strategic transaction costs, including costs attributable to the Lonestar Acquisition during the 2021 periods and the Juniper Transaction during the 2020 periods and first quarter 2021 as described in the discussion of "*Results of Operations – General and Administrative*" that follows.

Sequential Quarterly Analysis

The following summarizes our key operating and financial highlights for the three months ended December 31, 2021 with comparison to the three months ended September 30, 2021. The year-over-year highlights for 2021 and 2020 are addressed in further detail in the discussions that follow below in *Year over Year Analysis of Operating and Financial Results*.

- Daily sales volume increased approximately 58% to 40,236 boe per day from 25,483 boe per day due primarily to the impact of the Lonestar Acquisition which closed in October. Total sales volume increased approximately 58% to 3,702 Mboe from 2,344 Mboe due to the aforementioned factors.
- Product revenues increased 60% to $224.6 million from $140.1 million due primarily to 35% higher crude oil volume, or $44.5 million largely as a result of the Lonestar Acquisition in the fourth quarter of 2021, coupled with 11% higher crude oil prices, or $18.7 million. NGL revenues increased 156% due to 133% higher volume, or $9.5 million largely as a result of the Lonestar acquisition, as well as 10% higher prices, or $1.6 million. Natural gas revenues increased 205% due to 176% higher volume, or $8.8 million primarily driven by the Lonestar Acquisition in the fourth quarter of 2021 as well as 10% higher prices, or $1.4 million.
- Production and lifting costs, consisting of Lease operating expenses ("LOE") and Gathering, processing and transportation expenses ("GPT"), increased on an absolute basis to $24.3 million from $16.3 million, but decreased on a per unit basis to $6.57 per boe from $6.97 per boe due primarily the impact of the Lonestar Acquisition coupled with higher overall sales volume.
- Production and ad valorem taxes increased on an absolute basis to $11.3 million from $7.5 million, but decreased on a per unit basis to $3.05 per boe from $3.21 per boe, respectively, due primarily to the impact of the Lonestar Acquisition and higher product revenues and volumes, partially offset by the continued effect of substantially lower estimated valuations for ad valorem tax assessments.
- General and administrative expenses ("G&A") increased on an absolute and per unit basis to $35.4 million and $9.57 per boe from $10.9 million and $4.66 per boe, respectively, due primarily to higher fourth quarter 2021 costs incurred in connection with the Lonestar Acquisition for legal, accounting, advisory fees, as well as acquisition-related change-in-control severance and vesting of shares held by Lonestar employees and directors.
- Depreciation, depletion and amortization ("DD&A") increased on an absolute basis to $48.0 million from $31.0 million and decreased on a per unit basis from $13.21 per boe to $12.97 per boe due primarily to the Lonestar Acquisition, which contributed to an increase in our proved reserves at a lower relative cost per boe than our historical DD&A rate.

Year over Year Analysis of Operating and Financial Results

Sales Volume

The following tables set forth a summary of our total and average daily sales volumes by product for the periods presented:

Total Sales Volume [1]	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
Crude oil (Mbbl)	7,711	6,829	882	13 %
NGLs (Mbbl)	1,326	1,165	161	14 %
Natural gas (MMcf)	6,712	5,360	1,352	25 %
Total (Mboe)	10,155	8,887	1,268	14 %

Average Daily Sales Volume [1]	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
Crude oil (bbl/d)	21,125	18,658	2,467	13 %
NGLs (bbl/d)	3,632	3,182	450	14 %
Natural gas (MMcf/d)	18	15	3	20 %
Total (boe/d)	27,822	24,281	3,541	15 %

[1] All volumetric statistics represent volumes of commodity production that were actually sold during the periods presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

2021 vs. 2020. Total sales volume increased 14% during 2021 compared to 2020 primarily driven by the Lonestar Acquisition during October 2021. This is partially offset by the continued impact in 2021 from the temporary suspension of the drilling program in 2020 due to the global economic downturn associated with COVID-19 as our overall production levels remained depressed in early 2021.

During 2021, total crude oil sales volume was approximately 76% of total sales volume compared to approximately 77% during 2020. Crude oil composition of total sales volume during 2021 was impacted by the Lonestar Acquisition in October 2021, which has a higher natural gas and NGL content.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product for the periods presented:

Total Product Revenues	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
Crude oil	$ 517,301	$ 251,741	$ 265,560	105 %
NGLs	33,443	8,948	24,495	274 %
Natural gas	26,080	10,103	15,977	158 %
Total	$ 576,824	$ 270,792	$ 306,032	113 %

Product Revenues per Unit of Volume ($ per unit of volume)	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
Crude oil	$ 67.09	$ 36.86	$ 30.23	82 %
NGLs	$ 25.23	$ 7.68	$ 17.55	229 %
Natural gas	$ 3.89	$ 1.88	$ 2.01	107 %
Total	$ 56.80	$ 30.47	$ 26.33	86 %

The following table provides an analysis of the changes in our revenues for the periods presented:

	Year Ended December 31, 2021 vs. Year Ended December 31, 2020		
	Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ 32,513	$ 233,047	$ 265,560
NGLs	1,235	23,260	24,495
Natural gas	2,548	13,429	15,977
	$ 36,296	$ 269,736	$ 306,032

2021 vs. 2020. Our product revenues increased during 2021 compared to 2020 due primarily to significantly higher prices and the continued economic recovery following the easing of COVID-19 restrictions throughout the year, which resulted in increases to the NYMEX WTI benchmark price of 73% for 2021, as well as an increases in overall volumes due to the Lonestar Acquisition. Total crude oil revenues were approximately 90% and 93% of our total product revenues during 2021 and 2020, respectively.

Realized Differentials

The following table reconciles our realized price differentials from average NYMEX-quoted prices for WTI crude oil and HH natural gas for the periods presented:

	Year Ended December 31,			
	2021	2020	Change	% Change
Realized crude oil prices ($/bbl)	$ 67.09	$ 36.86	$ 30.23	82 %
Average WTI prices	68.11	39.46	$ 28.65	73 %
Realized differential to WTI	$ (1.02)	$ (2.60)	$ 1.58	(61)%
Realized natural gas prices ($/Mcf)	$ 3.89	$ 1.88	$ 2.01	107 %
Average HH prices ($/MMBtu)	3.82	1.99	$ 1.83	92 %
Realized differential to HH	$ 0.07	$ (0.11)	$ 0.18	(164)%

Beginning in March 2020, the adverse impact of COVID-19 and instability in the global energy markets effectively eliminated our premium margin to the NYMEX WTI index price for crude oil. Average NYMEX WTI crude oil prices have rebounded as stabilization continued throughout 2021, with crude oil averaging approximately $68.11 per bbl for 2021. Our realized crude oil prices for 2021 include the effect of added volumes from the Lonestar Acquisition in October 2021 during a period of higher prices. Beginning in March 2020, average NYMEX HH prices were also impacted by COVID-19 and the overall industry instability noted above, as well as by the colder than normal weather during first quarter 2021 that affected most of the lower 48 states and caused significant natural gas supply and demand imbalances. Recently, demand has rebounded while supply continues to be constrained, causing a significant increase in natural gas prices compared to the prior year as noted in the table above. See also the discussion of *Commodity Price and Other Economic Conditions* in the Overview above.

Effects of Derivatives

We present realized prices for crude oil, NGLs and natural gas, as adjusted for the effects of derivatives, net as we believe these measures are useful to management and stakeholders in determining the effectiveness of our price-risk management program that is designed to reduce the volatility associated with our operations. Realized prices for crude oil, natural gas liquids and natural gas, as adjusted for the effects of derivatives, net, are supplemental financial measures that are not prepared in accordance with GAAP.

The following table presents the calculation of our non-GAAP realized prices for crude oil, NGLs and natural gas, as adjusted for the effect of derivatives, net and reconciles to realized prices for crude oil, NGLs and natural gas determined in accordance with GAAP:

	Year Ended December 31,			
	2021	**2020**	**Change**	**% Change**
Realized crude oil prices ($/bbl)	$ 67.09	$ 36.86	$ 30.23	82 %
Effects of derivatives, net ($/bbl)	(10.94)	13.69	(24.63)	(180)%
Crude oil realized prices, including effects of derivatives, net ($/bbl)	$ 56.15	$ 50.55	$ 5.60	11 %
Realized NGL prices ($/bbl)	$ 25.23	$ 7.68	$ 17.55	229 %
Effects of derivatives, net ($/bbl)	(0.37)	—	(0.37)	100 %
NGL realized prices, including effects of derivatives, net ($/bbl)	$ 24.86	$ 7.68	$ 17.18	224 %
Realized natural gas prices ($/Mcf)	$ 3.89	$ 1.88	$ 2.01	107 %
Effects of derivatives, net ($/Mcf)	(0.88)	—	(0.88)	100 %
Natural gas realized prices, including effects of derivatives, net ($/Mcf)	$ 3.01	$ 1.88	$ 1.13	60 %

Effects of derivatives, net include, as applicable to the period presented: (i) current period commodity derivative settlements; (ii) the impact of option premiums paid or received in prior periods related to current period production; (iii) the impact of prior period cash settlements of early-terminated derivatives originally designated to settle against current period production; (iv) the exclusion of option premiums paid or received in current period related to future period production; and (v) the exclusion of the impact of current period cash settlements for early-terminated derivatives originally designated to settle against future period production.

Other Operating Income, Net

Other operating income, net, includes fees for marketing and water disposal services that we charge to third parties, net of related expenses, as well as other miscellaneous revenues and credits attributable to our current operations and gains and losses on the sale or disposition of assets other than our oil and gas properties. In addition, charges attributable to credit losses associated with our trade and joint venture partner receivables are netted within this caption.

The following table sets forth the total Other operating income, net recognized for the periods presented:

	Year Ended December 31,			
	2021	**2020**	**Change**	**% Change**
Other operating income, net	$ 2,667	$ 2,476	$ 191	8 %

2021 vs. 2020. Our marketing fee income increased in 2021 as compared to 2020 due primarily to higher commodity-based pricing and the recovery of certain suspended revenues attributable to prior years during 2021. The increase was partially offset by lower water disposal fees in 2021 due to lower sales volumes throughout most of the year as compared to 2020.

Lease Operating Expenses

LOE include costs that we incur to operate our producing wells and field operations. The most significant costs include compression and gas lift, chemicals, water disposal, repairs and maintenance, including down-hole repairs, field labor, pumping and well-tending, equipment rentals, utilities and supplies, among others.

The following table sets forth our LOE for the periods presented:

	Year Ended December 31,			
	2021	2020	Change	% Change
LOE	$ 45,402	$ 37,463	$ 7,939	21 %
Per unit ($/boe)	$ 4.47	$ 4.22	$ 0.25	6 %

2021 vs. 2020. LOE increased on an absolute basis and per unit basis during 2021 when compared to 2020 due primarily to a combination of higher variable costs, higher gas lift costs and the impact of the Lonestar acquisition, partially offset by continued cost-containment efforts and the application of operational improvements throughout 2021.

Gathering, Processing and Transportation

GPT expense includes costs that we incur to gather and aggregate our crude oil and natural gas production from our wells and deliver them via pipeline or truck to a central delivery point, downstream pipelines or processing plants, and blend or process, as necessary, depending upon the type of production and the specific contractual arrangements that we have with the applicable midstream operators. In addition, GPT expense includes short-term rental charges for crude oil storage tanks.

The following table sets forth our GPT expense for the periods presented:

	Year Ended December 31,			
	2021	2020	Change	% Change
GPT	$ 23,647	$ 22,050	$ 1,597	7 %
Per unit ($/boe)	$ 2.33	$ 2.48	$ (0.15)	(6) %

2021 vs. 2020. GPT expense increased on an absolute basis during 2021 as compared to 2020 due primarily to higher gas gathering costs attributable to 25% higher natural gas sales volumes, including additional volumes due to the Lonestar Acquisition. Additionally, for certain of our crude oil volumes gathered, our rate includes an adjustment based on NYMEX WTI prices. As crude oil prices increase, up to a cap of $90 per bbl, the gathering rate escalates. As such, with the higher prices during 2021 than in 2020, we incurred higher gathering costs associated with these volumes. These unfavorable variances were partially offset by the effects of an increase in the mix of crude oil volume sold at the wellhead, including the majority of crude oil volumes from the acquired Lonestar wells, resulting in overall lower transportation costs and cost per unit.

Production and Ad Valorem Taxes

Production or severance taxes represent taxes imposed by the state of Texas in which we operate, based on the market value of our crude oil, NGLs and natural gas produced. Ad valorem taxes represent taxes imposed by certain jurisdictions, primarily counties, in which we operate, based on the assessed value of our operating properties. The assessments for ad valorem taxes are generally based on published index prices.

The following table sets forth our production and ad valorem taxes for the periods presented:

	Year Ended December 31,			
	2021	2020	Change	% Change
Production/severance taxes	$ 27,246	$ 11,695	$ 15,551	133 %
Ad valorem taxes	3,795	4,924	(1,129)	(23) %
	$ 31,041	$ 16,619	$ 14,422	87 %
Per unit ($/boe)	$ 3.06	$ 1.87	$ 1.19	64 %
Production/severance tax rate as a percent of product revenues	4.7 %	4.3 %		

2021 vs. 2020. Production taxes increased on an absolute basis and per unit basis during 2021 when compared to 2020 due primarily to the increases in aggregate commodity sales prices in 2021. Our accruals for ad valorem taxes are based on our most recent estimates for assessments which reflect lower property values in 2021.

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A expenses, we have disaggregated certain costs into three components as presented in the table below. Primary G&A encompasses all G&A costs, except share-based compensation and certain significant special charges that are generally attributable to material stand-alone transactions or corporate actions that are not otherwise in the normal course.

The following table sets forth the components of G&A expenses for the periods presented:

	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
Primary G&A	$ 26,753	$ 24,086	$ 2,667	11 %
Share-based compensation [1]	15,589	3,284	12,305	375 %
Significant special charges:				
Organizational restructuring, including severance	367	1,446	(1,079)	(75) %
Acquisition/integration, divestiture and strategic transaction costs	23,820	4,973	18,847	379 %
Total G&A	$ 66,529	$ 33,789	$ 32,740	97 %
Per unit ($/boe)	$ 6.55	$ 3.80	$ 2.75	72 %
Per unit ($/boe) excluding share-based compensation and other significant special charges identified above	$ 2.63	$ 2.71	$ (0.08)	(3) %

[1] Share-based compensation for the year ended December 31, 2021 included $10.4 million related to the Lonestar Acquisition. See Note 4 and Note 16 for further details.

2021 vs. 2020. Our primary G&A expenses increased on an absolute and per unit basis during 2021 compared to 2020. The increase for 2021 compared to 2020 is due primarily to higher employee compensation costs.

Share-based compensation charges during the periods presented are attributable to the amortization of compensation cost, net of forfeitures, associated with the grants of time-vested restricted stock units (“RSUs”), and performance-based restricted stock units (“PRSUs”). The grants of RSUs and PRSUs are described in greater detail in Note 16 to the consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data”. As a result of the Juniper Transactions which qualified as a change-in-control event, all of the RSUs granted before 2019 vested as of the Juniper Closing Date in accordance with their terms. This resulted in an incremental charge of approximately $1.9 million during the first quarter 2021. Additionally, as a result of the Lonestar Acquisition, certain RSUs of Lonestar employees and directors immediately vested and $10.4 million was recorded as share-based compensation related to these vestings (see table above). All of our share-based compensation represents non-cash expenses.

Our total G&A expenses were higher on an absolute and per unit basis during during 2021 compared to 2020 due to higher overall incentive compensation and severance costs as well as acquisition and integration related costs associated with the Juniper Transactions and the Lonestar Acquisition, partially offset by lower organizational restructuring costs.

Depreciation, Depletion and Amortization (DD&A)

DD&A expense includes charges for the allocation of property costs based on the volume of production, depreciation of fixed assets other than oil and gas assets, as well as the accretion of our ARO liabilities.

The following table sets forth total and per unit costs for DD&A for the periods presented:

	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	% Change
DD&A	$ 131,657	$ 140,673	$ (9,016)	(6) %
DD&A rate ($/boe)	$ 12.96	$ 15.83	$ (2.87)	(18) %

2021 vs. 2020. DD&A decreased on an absolute and a per unit basis during 2021 when compared to 2020. Higher production volume provided for an increase of $20.1 million while lower DD&A rates in 2021 provided for a decrease of $29.1 million. The lower DD&A rate in 2021 was primarily attributable to the effect of adding additional reserves in 2021, including reserves associated with the Lonestar Acquisition, as well as the effect of the impairments recorded in the latter part of 2020 and in first quarter of 2021, as referenced and discussed further below.

Impairment of Oil and Gas Properties

We assess our oil and gas properties on a quarterly basis based on the results of a Ceiling Test in accordance with the full cost method of accounting for oil and gas properties.

	Year Ended December 31,			
	2021	2020	Change	% Change
Impairments of oil and gas properties	$ 1,811	$ 391,849	$ (390,038)	(100)%

2021 vs. 2020. During 2021 and 2020, we recorded impairments of our oil and gas properties as a result of the decline in the twelve-month average prices of crude oil, NGLs and natural gas as indicated by the respective quarterly Ceiling Test under the full cost method of accounting for oil and gas properties. See Note 7 for more discussion.

Interest Expense

Interest expense includes charges for outstanding borrowings under the Credit Facility and Second Lien Term Loan, derived from internationally-recognized interest rates with a premium based on our credit profile and the level of credit outstanding and the contractual rate associated with the 9.25% Senior Notes due 2026. In addition, we are assessed certain fees for the overall credit commitments provided to us as well as fees for credit utilization and letters of credit. Also included is the accretion of original issue discount ("OID") on the Second Lien Term Loan prior to repayment and the 9.25% Senior Notes due 2026 and the amortization of issuance costs capitalized attributable to the Credit Facility, the Second Lien Term Loan and the 9.25% Senior Notes due 2026. These costs are partially offset by interest amounts that we capitalize on unproved property costs while we are engaged in the evaluation of projects for the underlying acreage.

The following table summarizes the components of our interest expense for the periods presented:

	Year Ended December 31,			
	2021	2020	Change	% Change
Interest on borrowings and related fees	$ 34,029	29,851	$ 4,178	14 %
Amortization of debt issuance costs	2,248	3,339	(1,091)	(33) %
Accretion of original issue discount	487	811	(324)	(40) %
Capitalized interest	(3,603)	(2,744)	(859)	31 %
Total interest expense, net of capitalized interest	$ 33,161	$ 31,257	$ 1,904	6 %

2021 vs. 2020. The increase in interest expense during 2021 is substantially attributable to interest incurred in the amount of $14.8 million for the 9.25% Senior Notes due 2026. This is offset by decreased interest expense attributable to the Credit Facility and Second Lien Term Loan during 2021 as compared to 2020 due primarily to the effect of lower outstanding balances during 2021 and lower interest rates associated with the Credit Facility, resulting from lower applicable margins based on lower utilization levels and the payoff of the Second Lien Term Loan upon the closing of the Lonestar Acquisition. The weighted-average balances under the Credit Facility were lower in 2021 by approximately $111 million. The weighted-average interest rates during the same periods were lower by 40 basis points. The accretion of OID is attributable to the Second Lien Term Loan prior to repayment and 9.25% Senior Notes due 2026 and the amortization of debt issuance costs includes amounts attributable to the Credit Facility, Second Lien Term Loan and 9.25% Senior Notes due 2026. We capitalized a larger portion of interest during 2021 as we maintained a higher portion of unproved property as compared to 2020 due primarily to the acquisition of unproved properties in the Juniper Transactions and the Lonestar Acquisition coupled with the impact of additional interest related to the 9.25% Senior Notes due 2026.

Derivatives

The gains and losses for our derivatives portfolio reflect changes in the fair value attributable to changes in market values relative to our hedged commodity prices and interest rates.

The following table summarizes the gains and (losses) attributable to our commodity derivatives portfolio and interest rate swaps for the periods presented:

	Year Ended December 31,			
	2021	**2020**	**Change**	**% Change**
Commodity derivative gains (losses)	$ (136,997)	$ 95,932	$ (232,929)	(243)%
Interest rate swap gains (losses)	(2)	(7,510)	7,508	(100)%
Total	$ (136,999)	$ 88,422	$ (225,421)	(255)%

2021 vs. 2020. In 2021, commodity prices recovered to levels that were significantly higher on an average aggregate basis than those during 2020. Accordingly, the derivative losses in 2021 reflect the decline in the mark-to-market values consistent with the increase in prices attributable to open positions. The effect in 2020 was in the opposite direction as the mark-to-market gains were attributable to the substantial decline in prices for the underlying commodities relative to our hedged positions. In the second quarter 2021, we began hedging a portion of our NGL production. Realized settlement payments, net, for crude oil, NGL and natural gas derivatives were $77.1 million during 2021 as compared to realized settlement receipts, net of $80.3 million during 2020. In 2020, we began hedging a portion of our exposure to variable interest rates associated with our Credit Facility and Second Lien Term Loan. During 2021 and 2020, we paid $3.8 million and $2.2 million of net settlements from our interest rate swaps, respectively.

Income Taxes

Income taxes represent our income tax provision as determined in accordance with generally accepted accounting principles. It considers taxes attributable to our obligations for federal taxes under the Internal Revenue Code as well as to the various states in which we operate, primarily Texas, or otherwise have continuing involvement.

The following table summarizes our income tax provision for the periods presented:

	Year Ended December 31,			
	2021	**2020**	**Change**	**% Change**
Income tax (expense) benefit	$ (1,560)	$ 2,303	$ (3,863)	(168)%
Effective tax rate	(1.6)%	(0.7)%	(0.9)%	129 %

2021. The provision for the year ended December 31, 2021 includes a deferred state tax expense of $1.2 million attributable to property and equipment and $0.3 million of current state expense attributable to the Texas margin tax for the year ended December 31, 2021 for an overall effective tax rate of 1.6%.

2020. The provision for the year ended December 31, 2020 includes current federal benefits of $1.2 million attributable to refundable alternative minimum tax, or AMT, credits for the 2020 tax year, which when combined with the amounts attributable to 2019 that had been recognized on our consolidated balance sheets as of December 31, 2019 as a current asset, were received in 2020 as an acceleration of all AMT credits in connection with certain provisions of the CARES Act. This AMT benefit was offset by a corresponding decrease in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expense for the year ended December 31, 2020. In addition, we recognized a deferred state tax benefit of $2.7 million attributable to property and equipment and $0.4 million of current state expense attributable to the Texas margin tax for the year ended December 31, 2020 for an overall effective tax rate of 0.7%.

Liquidity and Capital Resources

Our primary sources of liquidity include our cash on hand, cash provided by operating activities and borrowings under the Credit Facility. As of December 31, 2021, we had liquidity of $214.8 million, comprised of cash and cash equivalents of $23.7 million and availability under our Credit Facility of $191.1 million (factoring in letters of credit). Additionally, following the closing of the Lonestar Acquisition, the borrowing base under the Credit Facility was increased to $600 million, with aggregate elected commitments of $400 million. Effective December 31, 2021, the borrowing base was further increased to $725 million, with aggregate elected commitments remaining at $400 million.

On August 10, 2021, our indirect, wholly-owned subsidiary Penn Virginia Escrow LLC (the "Escrow Issuer") completed an offering of $400 million aggregate principal amount of the 9.25% Senior Notes due 2026 which bear interest at 9.25% and were sold at 99.018% of par. The gross proceeds of the offering and other funds had initially been deposited in an escrow account pending satisfaction of certain conditions, including the consummation of the Lonestar Acquisition. Upon the closing of the Lonestar Acquisition, Holdings assumed all obligations under the 9.25% Senior Notes due 2026 and the net proceeds and certain other funds were released from escrow and used to repay and discharge certain long-debt of Lonestar including accrued interest and related expenses, and the remainder, along with cash on hand, was used to repay the Second Lien Term Loan including a prepayment premium, accrued interest and related expenses. See Note 9 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information.

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for crude oil, NGL and natural gas products, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. All of these factors have been negatively impacted by the COVID-19 pandemic and the related instability in the global energy markets. In order to mitigate this volatility, we are extensively utilizing derivative contracts with a number of financial institutions, all of which are participants in our Credit Facility, hedging a portion of our estimated future crude oil, NGLs and natural gas production through the first half of 2024. The level of our hedging activity and duration of the financial instruments employed depends on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

We continually evaluate potential sales of assets, including certain non-strategic oil and gas properties and undeveloped acreage, among others. Additionally, from time-to-time and under market conditions that we believe are favorable to us, we may consider capital market transactions, including the offering of debt and equity securities. We maintain an effective shelf registration statement to allow for optionality.

Capital Resources

We expect 2022 capital expenditures of up to approximately $435 million, of which approximately $425 million is expected to be allocated to drilling and completion activities. We plan to fund our 2022 capital program and our operations for the next twelve months primarily with cash on hand, cash from operating activities and, to the extent necessary, supplemental borrowings under the Credit Facility. Based upon current price and production expectations, we believe that our cash on hand, cash from operating activities and borrowings under our Credit Facility, as necessary, will be sufficient to fund our capital spending and operations for at least the next twelve months; however, future cash flows are subject to a number of variables including the current global economic uncertainties remaining after the COVID-19 pandemic and related instability in the global energy markets and geopolitical climate.

Additionally, we have other obligations primarily consisting of our outstanding debt principal and interest obligations, derivative instruments, service agreements, operating leases, and asset retirement and environmental obligations, all of which are customary in our business. See "Commitments and Contingencies" summarized below, as well as Note 6 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for more details related to these obligations.

In March 2022, we announced an intention to commence a quarterly dividend on our Class A Common Stock in the third quarter of 2022. Each Common Unit in the Partnership would be entitled to a distribution in the same amount of any dividend paid on the Class A Common Stock. We expect to fund all such dividends with cash flow from operations.

Cash Flows

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

	Year Ended December 31,	
	2021	2020
Net cash provided by operating activities	289,025	222,265
Net cash used in investing activities	(245,174)	(168,478)
Net cash provided by (used in) financing activities	(33,190)	(48,565)
Net increase (decrease) in cash and cash equivalents	$ 10,661	$ 5,222

Cash Flows from Operating Activities. The increase of $66.8 million in net cash from operating activities for 2021 compared to 2020 was primarily attributable to the effect of cash receipts that were derived from higher average prices and total sales volumes in 2021, net of interest rate swap settlements in the 2021 period as compared to 2020, partially offset by (i) higher net payments for commodity derivatives settlements and premiums, (ii) transaction costs paid in connection with the Juniper Transactions and Lonestar Acquisition and related integration costs, and (iii) executive restructuring costs, including severance payments.

Cash Flows from Investing Activities. Our cash payments for capital expenditures were higher during 2021 compared to 2020, due primarily to the suspension of the drilling and completion program for approximately half of the year in 2020 as a result of the COVID-19 pandemic and related market instability.

The following table sets forth costs related to our capital expenditure program for the periods presented:

	Year Ended December 31,	
	2021	2020
Drilling and completion	$ 263,936	$ 125,626
Lease acquisitions, land-related costs, and geological and geophysical (seismic) costs	3,773	3,789
Pipeline, gathering facilities and other equipment, net [1]	(1,252)	1,193
Total capital expenditures program costs	$ 266,457	$ 130,608

[1] Includes certain capital charges to our working interest partners for completion services.

The following table reconciles the total costs of our capital expenditure program with the net cash paid for capital expenditures as reported in our consolidated statements of cash flows for the periods presented:

	Year Ended December 31,	
	2021	2020
Total capital expenditures program costs (from above)	$ 266,457	$ 130,608
Decrease (increase) in accounts payable for capital items and accrued capitalized costs	(16,726)	18,671
Net purchases/(transfers) of tubular inventory and well materials [1]	3,388	867
Prepayments for drilling and completion services, net of (transfers)	(4,018)	13,608
Capitalized internal labor, capitalized interest and other	7,242	4,811
Total cash paid for capital expenditures	$ 256,343	$ 168,565

[1] Includes purchases made in advance of drilling.

Cash Flows from Financing Activities. During 2021, we received net proceeds of $396.1 million from the offering of the 9.25% Senior Notes due 2026 in connection with the Lonestar Acquisition and $151.2 million from the issuance of equity in connection with the Juniper Transactions (See Note 4). The proceeds from these transactions were primarily used to: (i) repay and discharge $249.6 million of Lonestar's outstanding long-term debt, (ii) repay the $200 million Second Lien Term Loan, (iii) repayments of $80.5 million under the Credit Facility, and (iv) pay $9.3 million of transaction and issue costs related to Juniper. Additionally, during 2021, we had borrowings of $70.0 million and additional repayments of $95.9 million under the Credit Facility and paid $14.4 million in debt issuance costs. During 2020, we had borrowings of $51.0 million and repayments of $99.0 million under the Credit Facility which were used to fund a portion of the capital program at the beginning of 2020.

Capitalization

The following table summarizes our total capitalization as of the dates presented:

	December 31,	
	2021	2020
Credit Facility borrowings	$ 208,000	$ 314,400
Second Lien Term Loan, net	—	195,097
9.25% Senior Notes due 2026, net	386,427	—
Mortgage debt [1]	8,438	—
Other	2,516	—
Total debt, net	605,381	509,497
Total equity	669,508	212,838
Total capitalization	$ 1,274,889	$ 722,335
Debt as a % of total capitalization	47 %	71 %

[1] The mortgage debt relates to the corporate office building and related assets acquired in connection with the Lonestar Acquisition for which assets are held as collateral for such debt. As of December 31, 2021, these assets met the held for sale criteria and were classified as Assets held for sale on our consolidated balance sheets in our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data.".

Credit Facility. As of December 31, 2021, the Credit Facility had a $1.0 billion revolving commitment and a $725 million borrowing base, with aggregate elected commitments of $400 million and a $25 million sublimit for the issuance of letters of credit. The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes including working capital. We had $0.9 million and $0.4 million in letters of credit outstanding as of December 31, 2021 and 2020. The maturity date under the Credit Facility is October 6, 2025.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a Eurodollar rate plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on Eurodollar borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of December 31, 2021, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.26%. Unused commitment fees are charged at a rate of 0.50%.

The following table summarizes our borrowing activity under the Credit Facility for the periods presented:

	Borrowings Outstanding			
	End of Period	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2021	$ 208,000	$ 245,661	$ 262,900	3.22 %
Year ended December 31, 2021	$ 208,000	$ 242,329	$ 314,400	3.15 %

The Credit Facility is guaranteed by all of the subsidiaries of the borrower (the "Guarantor Subsidiaries"), except for Boland Building, LLC which holds real estate assets that are associated with mortgage obligations assumed in the Lonestar Acquisition. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on the ability of the borrower or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our subsidiaries' assets.

Second Lien Term Loan. On October 5, 2021, Holdings repaid all of its outstanding obligations under the Second Lien Term Loan, and terminated the Second Lien Term Loan. In accordance with the Second Lien Term Loan, we incurred a prepayment premium of 102% as a result of repayment. In connection with the repayment of the Second Lien Term Loan, we incurred costs related to the premium and write off of unamortized discount and issuance costs of $6.9 million recorded as a loss on extinguishment of debt.

9.25% Senior Notes due 2026. On August 10, 2021, our indirect, wholly-owned subsidiary Penn Virginia Escrow LLC (the "Escrow Issuer") completed an offering of $400 million aggregate principal amount of senior unsecured notes due 2026 (the "9.25% Senior Notes due 2026") that bear interest at 9.25% and were sold at 99.018% of par. Obligations under the 9.25% Senior Notes due 2026 were assumed by Holdings, as borrower, and are guaranteed by the subsidiaries of Holdings that guarantee the Credit Facility.

Covenant Compliance. As of December 31, 2021, the Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset) of 1.00 to 1.00 and (2) a maximum leverage ratio (consolidated indebtedness to EBITDAX, each as defined in the Credit Facility), in each case measured as of the last day of each fiscal quarter of 3.50 to 1.00.

The Credit Facility and the Indenture contains customary affirmative and negative covenants as well as events of default and remedies including certain anti-hoarding provisions. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of December 31, 2021, the Company was in compliance with all debt covenants as of December 31, 2021.

See Note 9 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information on our debt.

Commitments and Contingencies

Long-Term Debt

We have long-term debt obligations that have various maturities and interest rates. For information on our debt obligations, see Note 9 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for more details.

Leases

We have various non-cancelable operating leases in connection with the leases of our office facilities and equipment. See Note 11 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for further information.

Gathering and Intermediate Transportation Commitments

We have agreements for gathering and intermediate pipeline transportation services for our crude oil and condensate production. For further details on these agreements, see Note 14 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Asset Retirement Obligations

We have AROs that primarily relate to the plugging and abandonment of oil and gas wells. For information on our AROs, see Note 8 and Note 14 to the consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Critical Accounting Estimates

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting estimates requiring judgment of our management.

Oil and Gas Reserves

Estimates of our oil and gas reserves are the most critical estimate included in our consolidated financial statements. Reserve estimates become the basis for determining depletive write-off rates and the recoverability of historical cost investments. There are many uncertainties inherent in estimating crude oil, NGL and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

There are several factors which could change the estimates of our oil and gas reserves. Significant rises or declines in commodity product prices as well as changes in our drilling plans could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs.

Oil and Gas Properties

We apply the full cost method to account for our oil and gas properties. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of DD&A.

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case, the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A. Factors we consider in our assessment include drilling results, the terms of oil and gas leases not held by production and drilling and completion capital expenditures consistent with our plans.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated after-tax discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated after-tax discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. During the first quarter of 2021, the carrying value of our proved oil and gas properties exceeded the limit determined by the Ceiling Test, resulting in a $1.8 million impairment. There were no other such impairments during 2021. During 2020, the carrying value of our proved oil and gas properties exceeded the limit determined by the Ceiling Test in the second, third and fourth quarters of 2020, resulting in a total of $391.8 million of impairment charges recorded for the year ended December 31, 2020.

Derivative Activities

We utilize derivative instruments, typically swaps, put options and call options which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. All derivative instruments are recognized in our consolidated financial statements at fair value with the changes recorded currently in earnings. We determine the fair values of our commodity derivative instruments using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatilities, time value and non-performance risk. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Deferred Tax Asset Valuation Allowance

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized after consideration of expected future taxable income and reasonable tax planning strategies. In the event that we were to determine that we would not be able to realize all or a part of our deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of our deferred tax assets is attributable to net operating losses at the federal level as well as certain states in which we operate. Estimates of future taxable income inherently reflect a significant degree of uncertainty. As of December 31, 2021, we believe it is more likely than not that we will not have sufficient future taxable income to realize the benefit of our gross deferred tax assets and, accordingly, have maintained a full valuation allowance.

Determination of Fair Value in Business Combinations

Accounting for the acquisition of a business requires allocation of the purchase price to the various assets acquired and liabilities assumed at their respective fair values. The determination of fair value requires the use of significant estimates and assumptions, and in making these determinations management uses all available information. If necessary, we have up to one year after the acquisition closing date to finalize these fair value determinations. For assets acquired in a business combination, the determination of fair value utilizes several valuation methodologies including discounted cash flows, which has assumptions with respect to the timing and amount of future revenue and expenses associated with an asset, and in the case of oil and gas companies, these as they relate to the reserves associated with its oil and gas properties. The assumptions made in performing these valuations include, but are not limited to, discount rate, future revenues and operating costs, projections of capital costs, and other assumptions believed to be consistent with those used by principal market participants. Due to the specialized nature of these calculations, we engage third-party specialists to assist management in evaluating our assumptions as well as appropriately measuring the fair value of assets acquired and liabilities assumed.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

Our interest rate risk is attributable to our borrowings under the Credit Facility, which is subject to variable interest rates. As of December 31, 2021, we had borrowings of $208.0 million under the Credit Facility at an interest rate of 3.26%. Assuming a constant borrowing level under the Credit Facility, an increase (decrease) in the interest rate of 1% would result in an increase (decrease) in aggregate interest payments of approximately $2.1 million on an annual basis, excluding the offsetting impact of our interest rate swap derivatives.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars and swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of crude oil, NGLs and natural gas.

As of December 31, 2021, our commodity derivative portfolio was in a net liability position in the amount of $59.1 million. The contracts associated with this position are with eight counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

During the year ended December 31, 2021, we reported a net commodity derivative loss of $137.0 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 6 to our consolidated financial statements included in Part II, Item 8, “Financial Statements and Supplementary Data” for a further description of our commodity price risk management activities.

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that crude oil and natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling outstanding derivative positions.

	Change of 10% per bbl of Crude Oil ($ in millions)	
	Increase	**Decrease**
Effect on the fair value of crude oil derivatives [1]	$ (44.6)	$ 36.1
Effect on 2022 operating income, excluding derivatives [2]	$ 67.5	$ (83.5)

[1] Based on derivatives outstanding as of December 31, 2021.

[2] Based on our 2022 Business Plan consistent with the assumptions used to determine our proved reserves as disclosed in Item 2, “Properties – *Summary of Oil and Gas Reserves* .” These sensitivities are subject to significant change.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Ranger Oil Corporation

Opinion on the financial statements

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 8, 2022 expressed an unqualified opinion.

Basis for opinion

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

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

Critical audit matters

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

The development of estimated proved reserves used in the calculation of depletion, depreciation and amortization expense and evaluation for impairment under the full cost method of accounting

As described further in Note 3 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and assess its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future net revenue, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment assessment. We identified the estimation of proved reserves of oil and gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions necessary to estimate the volumes and future net revenues of the Company's proved reserves require a high degree of subjectivity and could have a significant impact on the measurement of depletion expense and potential impairment. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and gas properties for potential impairment.
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.
- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:
    - We compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials
    - We tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs
    - We evaluated the method used to determine the future capital costs and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells to ascertain its reasonableness
    - We tested the working and net revenue interests used in the reserve report by inspecting land and division order records
    - We evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability and intent to develop the proved undeveloped properties
    - We applied analytical procedures to the reserve report forecasted production by comparing to historical actual results and to the prior year reserve report

Valuation of oil and gas properties and related proved producing reserves associated with the Lonestar Acquisition

As described further in Note 4 to the financial statements, the Company acquired certain producing oil & natural gas assets from Lonestar Resources US Inc. (collectively, "Lonestar," the "Lonestar Acquisition"), which required management to make estimates of the fair value associated with proved reserves and related discounted net cash flows. To estimate the volumes of proved reserves and the associated revenues, management makes significant estimates and assumptions related to the forecasted production decline rate of proved properties. Management also utilized a valuation specialist for the valuation of acquired proved reserves. In addition, the estimation of proved reserves is also impacted by management's judgments and assumptions regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of fair value. We identified the estimation of proved reserves oil and gas properties acquired as a critical audit matter.

The principal consideration for our determination that the valuation of proved reserves acquired in the Lonestar Acquisition is a critical audit matter is that changes in certain inputs and assumptions necessary to evaluate the volume and future discounted cash flows of the Company's proved reserves require a high degree of subjectivity and could have a significant impact on the measurement of fair value. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of controls relating to management's estimation of proved reserves acquired for the purpose of estimating fair value.
- We evaluated the independence, objectivity, and professional qualifications of the Lonestar reserve engineer used in determining the proved reserve volumes of the acquired Lonestar producing oil and gas properties.
- We evaluated the independence, objectivity, and professional qualifications of the Company's external valuation specialists, made inquiries of those valuation specialists regarding the process followed and judgements made to determine the fair value associated with proved reserve volumes, utilized our valuation specialists to assist in evaluating the appropriateness of the inputs and methodology used in the cash flow model (including future

commodity prices and weighted average cost of capital), and read the valuation report prepared by the external specialists.

- To the extent key, sensitive inputs and assumptions used to determine the fair value of the acquired proved reserve volumes and other cash flow inputs were analyzed by testing management's process for determining the assumption, including examining the underlying support. Specifically, our audit procedures involved testing management's assumptions as follows:
  - We evaluated the forecasted pricing used in the reserve report for reasonableness against market indices
  - We compared the estimated pricing differentials used in the reserve report to historical prices realized by Lonestar
  - We evaluated the reasonableness of future operating costs in the acquisition reserve report and compared amounts to historical operating costs realized by Lonestar
  - We tested the working and net revenue interests used in the reserve report by inspecting land and division order records on a sample basis, and compared interests within the reserve report against historical averages of Lonestar
  - We applied analytical procedures to production forecasts in the reserve report by comparing to historical actual results, and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas
March 8, 2022

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Ranger Oil Corporation

Opinion on internal control over financial reporting

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2021, and our report dated March 8, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Our audit of, and opinion on, the Company's internal control over financial reporting does not include the internal control over financial reporting of Lonestar Resources US Inc., a wholly-owned subsidiary, whose financial statements reflect total assets and revenues constituting 33 and 11 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2021. As indicated in Management's Report, Lonestar Resources US Inc. was acquired during 2021. Management's assertion on the effectiveness of the Company's internal control over financial reporting excluded internal control over financial reporting of Lonestar Resources US Inc.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Houston, Texas
March 8, 2022

RANGER OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2021	**2020**	**2019**
Revenues			
Crude oil	$ 517,301	$ 251,741	$ 434,713
Natural gas liquids	33,443	8,948	16,589
Natural gas	26,080	10,103	17,733
Other operating income, net	2,667	2,476	2,181
Total revenues and other	579,491	273,268	471,216
Operating expenses			
Lease operating	45,402	37,463	43,088
Gathering, processing and transportation	23,647	22,050	23,197
Production and ad valorem taxes	31,041	16,619	28,057
General and administrative	66,529	33,789	25,484
Depreciation, depletion and amortization	131,657	140,673	174,569
Impairments of oil and gas properties	1,811	391,849	—
Total operating expenses	300,087	642,443	294,395
Operating income (loss)	279,404	(369,175)	176,821
Other income (expense)			
Interest expense, net of amounts capitalized	(33,161)	(31,257)	(35,811)
Loss on extinguishment of debt	(8,860)	—	—
Derivatives	(136,999)	88,422	(68,131)
Other, net	94	(850)	(153)
Income (loss) before income taxes	100,478	(312,860)	72,726
Income tax (expense) benefit	(1,560)	2,303	(2,137)
Net income (loss)	98,918	(310,557)	70,589
Net income attributable to Noncontrolling interest	(58,689)	—	—
Net income (loss) attributable to common shareholders	$ 40,229	$ (310,557)	$ 70,589
Net income (loss) per share attributable to common shareholders:			
Basic	$ 2.41	$ (20.46)	$ 4.67
Diluted	$ 2.34	$ (20.46)	$ 4.67
Weighted average shares outstanding – basic	16,695	15,176	15,110
Weighted average shares outstanding – diluted	17,165	15,176	15,126

See accompanying notes to consolidated financial statements.

RANGER OIL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
Net income (loss)	$ 98,918	$ (310,557)	$ 70,589
Other comprehensive income (loss):			
Change in pension and postretirement obligations, net of tax	20	(72)	(141)
Comprehensive income (loss)	98,938	(310,629)	70,448
Net income attributable to Noncontrolling interest	(58,689)	—	—
Other comprehensive income attributable to Noncontrolling interest	(23)	—	—
Comprehensive income (loss) attributable to common shareholders	$ 40,226	$ (310,629)	$ 70,448

See accompanying notes to consolidated financial statements.

RANGER OIL CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2021	December 31, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 23,681	$ 13,020
Accounts receivable, net of allowance for credit losses	118,594	45,849
Derivative assets	11,478	75,506
Prepaid and other current assets	20,998	19,045
Assets held for sale	11,400	—
Total current assets	186,151	153,420
Property and equipment, net (full cost method)	1,383,348	723,549
Derivative assets	2,092	25,449
Other assets	5,017	4,908
Total assets	$ 1,576,608	$ 907,326
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 214,381	$ 63,089
Derivative liabilities	50,372	85,106
Current portion of long-term debt	4,129	—
Total current liabilities	268,882	148,195
Deferred income taxes	2,793	—
Derivative liabilities	23,815	28,434
Other non-current liabilities	10,358	8,362
Long-term debt, net	601,252	509,497
Commitments and contingencies (Note 14)		
Equity		
Preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued as of December 31, 2021 and 2020, respectively	—	—
Class A common stock of $0.01 par value – 110,000,000 shares authorized; 21,090,259 and 15,200,435 shares issued as of December 31, 2021 and 2020, respectively	729	152
Class B common stock of $0.01 par value – 30,000,000 shares authorized; 22,548,998 shares issued as of December 31, 2021	2	—
Paid-in capital	273,329	203,463
Retained earnings	49,583	9,354
Accumulated other comprehensive loss	(111)	(131)
Ranger Oil shareholders' equity	323,532	212,838
Noncontrolling interest	345,976	—
Total equity	669,508	212,838
Total liabilities and shareholders' equity	$ 1,576,608	$ 907,326

See accompanying notes to consolidated financial statements.

RANGER OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
Cash flows from operating activities			
Net income (loss)	$ 98,918	$ (310,557)	$ 70,589
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Loss on extinguishment of debt	8,860	—	—
Depreciation, depletion and amortization	131,657	140,673	174,569
Impairments of oil and gas properties	1,811	391,849	—
Derivative contracts:			
Net (gains) losses	136,999	(88,422)	68,131
Cash settlements and premiums received (paid), net	(130,475)	78,087	(4,136)
Deferred income tax expense (benefit)	1,249	(1,424)	3,373
Non-cash interest expense	2,735	4,150	3,354
Share-based compensation	15,589	3,284	4,082
Other, net	19	13	47
Changes in operating assets and liabilities:			
Accounts receivable, net	(38,676)	28,078	(5,079)
Accounts payable and accrued expenses	60,338	(24,244)	5,736
Other assets and liabilities	1	778	574
Net cash provided by operating activities	289,025	222,265	321,240
Cash flows from investing activities			
Acquisitions, net of cash acquired (paid)	11,009	—	(6,516)
Capital expenditures	(256,343)	(168,565)	(362,743)
Proceeds from sales of assets, net	160	87	215
Net cash used in investing activities	(245,174)	(168,478)	(369,044)
Cash flows from financing activities			
Proceeds from credit facility borrowings	70,000	51,000	76,400
Repayments of credit facility borrowings	(176,400)	(99,000)	(35,000)
Repayments of second lien term loan	(200,000)	—	—
Proceeds from 9.25% Senior Notes due 2026, net of discount	396,072	—	—
Repayments of acquired and other debt	(249,700)	—	—
Proceeds from redeemable common units	151,160	—	—
Proceeds from redeemable preferred stock	2	—	—
Transaction costs paid on behalf of Noncontrolling interest	(5,543)	—	—
Issuance costs paid for Noncontrolling interest securities	(3,758)	—	—
Withholding taxes for share-based compensation	(656)	(487)	(1,046)
Debt issuance costs paid	(14,367)	(78)	(2,616)
Net cash provided by (used in) financing activities	(33,190)	(48,565)	37,738
Net increase (decrease) in cash and cash equivalents	10,661	5,222	(10,066)
Cash and cash equivalents – beginning of period	13,020	7,798	17,864
Cash and cash equivalents – end of period	$ 23,681	$ 13,020	$ 7,798
Supplemental disclosures:			
Cash paid for:			
Interest, net of amounts capitalized	$ 15,609	$ 27,333	$ 32,398
Income tax refunds, net of payments	$ 288	$ (2,471)	$ (2,471)
Non-cash investing and financing activities:			
Changes in property and equipment related to capital contributions	$ (38,561)	$ —	$ —
Changes in accrued liabilities related to capital expenditures	$ 16,726	$ (18,671)	$ (3,602)
Change in property and equipment related to acquisitions	$ (480,563)	$ —	$ (6,211)
Equity and replacement awards issued as consideration in the Lonestar Acquisition	$ 173,576	$ —	$ —

See accompanying notes to consolidated financial statements.

RANGER OIL CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Preferred Stock	Common Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
December 31, 2018	$ —	15,080	$ 151	$ 197,630	$ 249,492	$ 82	$ —	$ 447,355
Net income	—	—	—	—	70,589	—	—	70,589
Share-based compensation	—	—	—	4,082	—	—	—	4,082
Restricted stock unit vesting	—	56	—	(1,046)	—	—	—	(1,046)
Cumulative effect of change in accounting principle	—	—	—	—	(94)	—	—	(94)
All other changes	—	—	—	—	—	(141)	—	(141)
December 31, 2019	—	15,136	151	200,666	319,987	(59)	—	520,745
Net loss	—	—	—	—	(310,557)	—	—	(310,557)
Share-based compensation	—	—	—	3,284	—	—	—	3,284
Restricted stock unit vesting	—	64	1	(487)	—	—	—	(486)
Cumulative effect of change in accounting principle	—	—	—	—	(76)	—	—	(76)
All other changes	—	—	—	—	—	(72)	—	(72)
December 31, 2020	—	15,200	152	203,463	9,354	$ (131)	$ —	212,838
Net income	—	—	—	—	40,229	—	58,689	98,918
Issuance of preferred stock	2	—	—	—	—	—	—	2
Issuance of Noncontrolling interest	—	—	—	(50,068)	—	—	229,620	179,552
Share-based compensation	—	—	—	15,589	—	—	—	15,589
Restricted stock unit vesting	—	140	2	(658)	—	—	—	(656)
Conversion of preferred stock into common stock	(2)	—	2	—	—	—	—	—
Issuance of common stock related to the Lonestar Acquisition [1]	—	5,750	575	162,607	—	—	—	163,182
Change in ownership related to the Lonestar Acquisition	—	—	—	(57,604)	—	—	57,644	40
All other changes	—	—	—	—	—	20	23	43
December 31, 2021	$ —	21,090	$ 731	$ 273,329	$ 49,583	$ (111)	$ 345,976	$ 669,508

[1] Includes $4.5 million attributed to pre-combination services for replacement awards issued in connection with the Lonestar Acquisition. See Note 4 and Note 16 for further details.

See accompanying notes to consolidated financial statements.

Note 1 – Nature of Operations

Ranger Oil Corporation (together with its consolidated subsidiaries, unless the context otherwise requires, "Ranger Oil," the "Company," "we," "us" or "our") is an independent oil and gas company focused on the onshore development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in South Texas. We operate in and report our financial results and disclosures as one segment, which is the development and production of crude oil, NGLs and natural gas.

On October 5, 2021 (the "Closing Date"), the Company acquired Lonestar Resources US Inc., a Delaware corporation ("Lonestar"), as a result of which Lonestar and its subsidiaries became wholly-owned subsidiaries of the Company (the "Lonestar Acquisition"). The Lonestar Acquisition was effected pursuant to the Agreement and Plan of Merger (the "Merger Agreement"), dated July 10, 2021, by and between the Company and Lonestar. Following the completion of the Lonestar Acquisition, the Company changed its name from Penn Virginia Corporation ("Penn Virginia") to Ranger Oil Corporation, and its Class A Common Stock ("Class A Common Stock"), par value of $ 0.01 per share, began trading on The Nasdaq Global Select Market ("Nasdaq") under the symbol "ROCC" on October 18, 2021.

Note 2 – Basis of Presentation

A substantial noncontrolling interest in our subsidiaries is provided for in our consolidated statements of operations and comprehensive income (loss) as well as our consolidated balance sheets as of and for the period ended December 31, 2021 (see Note 4 for additional detail including the basis of presentation of the noncontrolling interest). Our consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP") and the rules and regulations of the Securities and Exchange Commission (the "SEC"). Preparation of these statements involves the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of our consolidated financial statements, have been included. Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications did not have a material impact on prior period financial statements. As the Lonestar Acquisition was completed on October 5, 2021, our consolidated financial statements include Lonestar's financial information and operating results from the Closing Date to the period ended December 31, 2021.

Note 3 – Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of Ranger Oil and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

Preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Such estimates include certain asset and liability valuations as further described in these notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. Some of our account balances exceed the FDIC coverage limits. We believe our cash and cash equivalents are not subject to any material interest rate risk, equity price risk, credit risk or other market risk.

Derivative Instruments

We utilize derivative instruments, which are placed with financial institutions that we believe are of acceptable credit risk, to mitigate our financial exposure to commodity price and interest rate volatility. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in our consolidated financial statements at fair value. We have elected to report all of our derivative asset and liability positions on a gross basis on our consolidated balance sheets and not net the positions, even when a legal right-of-setoff exists. Our derivative instruments are not formally designated as hedges in the context of GAAP. In accordance with our internal policies, we do not utilize derivative instruments for speculative purposes. We recognize changes in fair value in earnings currently as a component of the Derivatives caption in our consolidated statements of operations. See Note 6.

Property and Equipment

Oil and Gas Properties

We apply the full cost method of accounting for our oil and gas properties. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of depreciation, depletion and amortization ("DD&A").

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated after-tax discounted future net revenues from proved properties adjusted for costs excluded from amortization (the "Ceiling Test"). The estimated after-tax discounted future net revenues are determined using the prior 12-month's average commodity prices based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development.

DD&A of our oil and gas properties is computed using the units-of-production method. We apply this method by multiplying the unamortized cost of our proved oil and gas properties, net of estimated salvage plus future development costs, by a rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period.

Other Property and Equipment

Other property and equipment consists primarily of gathering systems and related support equipment, vehicles, leasehold improvements, information technology hardware and capitalized software costs. Other property and equipment are carried at cost and include expenditures for additions and improvements which increase the productive lives of existing assets. Renewals and betterments, which extend the useful life of the properties, are also capitalized. Maintenance and repair costs are charged to expense as incurred. We compute depreciation and amortization of property and equipment using the straight-line method over the estimated useful life of each asset as follows: Gathering systems – 15 to 20 years and Other property and equipment – three to 20 years.

Leases

We determine if a contractual arrangement is a lease at inception and whether it is classified as operating or financing based on whether that contract conveys the right to control the use of an identified asset in exchange for consideration for a period of time. Leases are included in Other assets, Accounts payable and accrued liabilities and Other liabilities on our consolidated balance sheets and are identified as Right-of-use ("ROU") assets, Current lease obligations and Noncurrent lease obligations, respectively, in Note 11 and Note 12.

ROU assets represent our right to use an underlying asset for the lease term and lease obligations represent our obligation to make lease payments arising from the underlying contractual arrangement. Operating lease ROU assets and obligations are recognized at the commencement date based on the present value of lease payments over the lease term. The operating lease ROU assets include any lease payments made in advance and excludes lease incentives. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise such options. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

Most of our leasing arrangements do not identify or otherwise provide for an implicit interest rate. Accordingly, we utilize a secured incremental borrowing rate based on information available at the commencement date in the determination of the present value of the lease payments. As most of our lease arrangements have terms ranging from two to five years, our secured incremental borrowing rate is primarily based on the rates applicable to our Credit Facility.

We have lease arrangements that include lease and certain non-lease components, including amounts for related taxes, insurance, common area maintenance and similar terms. We apply a practical expedient provided in Accounting Standards Codification ("ASC") Topic 842, *Leases*, to not separate the lease and non-lease components. Accordingly, the ROU assets and lease obligations for such leases will include the present value of the estimated payments for the non-lease components over the lease term.

Certain of our lease arrangements with contractual terms of 12 months or less are classified as short-term leases. Accordingly, we do not include the underlying ROU assets and lease obligations on our consolidated balance sheets. The associated costs are aggregated with all of our other lease arrangements and are disclosed in the tables in Note 11.

Certain of our lease arrangements result in variable lease payments which, in accordance with ASC Topic 842, do not give rise to lease obligations. Rather, the basis and terms and conditions upon which such variable lease payments are determined are disclosed in Note 11.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. Associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in the DD&A expense caption in our consolidated statements of operations.

Income Taxes

We recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Using this method, deferred tax assets and liabilities are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and our ability to utilize operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent it may be incurred, as a component of interest expense and penalties as a component of income tax expense.

We are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

Noncontrolling interest

Noncontrolling interest in the accompanying consolidated financial statements represents the ownership interest held by Juniper and is presented as a component of equity. When the Company's relative ownership interest in the Partnership change, adjustments to noncontrolling interest and additional paid-in-capital, tax effected, will occur. Because these changes in the ownership interest in the Partnership do not result in a change of control, the transactions are accounted for as equity transactions under ASC Topic 810, *Consolidation*, which requires that any differences between the carrying value of the Company's basis in the Partnership and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest.

Revenue Recognition and Associated Costs

The Company recognizes revenue in accordance with ASC Topic 606, *Revenue from Contracts with Customers* which includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

We record revenue in the month that our oil and gas production is delivered to our customers. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized. See Note 5 for further discussion.

Substantially all of our commodity product sales are short-term in nature with contract terms of one year or less. We apply a practical expedient which provides for an exemption 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. Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create material contract assets or liabilities.

Crude oil. We sell our crude oil production to our customers at either the wellhead or a contractually agreed-upon delivery point, including certain regional central delivery point terminals or pipeline inter-connections. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality, location differentials and, if applicable, deductions for intermediate transportation. Costs incurred by us for gathering and transporting the products to an agreed-upon delivery point are recognized as a component of gathering, processing and transportation expense (“GPT”).

NGLs. We have natural gas processing contracts in place with certain midstream processing vendors. We deliver “wet” natural gas to our midstream processing vendors at the inlet of their processing facilities through gathering lines, certain of which we own and others which are owned by gathering service providers. Subsequent to processing, NGLs are delivered or transported to a third-party customer. Depending upon the nature of the contractual arrangements with the midstream processing vendors regarding the marketing of the NGL products, we recognize revenue for NGL products on either a gross or net basis. For those contracts where we have determined that we are the principal, and the ultimate third party is our customer, we recognize revenue on a gross basis, with associated processing costs presented as GPT expenses. For those contracts where we have determined that we are the agent and the midstream processing vendor is our customer, we recognize NGL product revenues on a net basis with processing costs presented as a reduction of revenue.

Natural gas. Subsequent to the processing of “wet” natural gas and the separation of NGL products, the “dry” or residue gas is purchased by the processor or delivered to us at the tailgate of the midstream processing vendors’ facilities and sold to a third-party customer. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality and location differentials, as applicable. Costs incurred by us for gathering and transportation from the wellhead through the processing facilities are recognized as a component of GPT expenses.

Marketing and water disposal services. We provide marketing and water disposal services to certain of our joint venture partners and other third parties with respect to oil and gas production for which we are the operator. Pricing for such services represents a fixed rate fee based, in the case of marketing services, on the sales price of the underlying oil and gas products and, in the case of water services, on the quantity of water volume processed. Marketing revenue is recognized simultaneously with the sale of our commodity production to our customers while water service revenue is recognized in the month that the service is rendered. Direct costs associated with our marketing efforts are included in G&A expenses and direct costs associated with our water service efforts are netted against the underlying revenue.

Credit Losses

We monitor and assess our portfolio of accounts receivable, including those from our customers, our joint interest partners and others, when applicable, for credit losses on a monthly basis as we originate the underlying financial assets. Our review process and related internal controls take into appropriate consideration (i) past events and historical experience with the identified portfolio segments, (ii) current economic and related conditions within the broad energy industry as well as those factors with broader applicability and (iii) reasonable supportable forecasts consistent with other estimates that are inherent in our financial statements. In order to facilitate our processes for the review and assessment of credit losses, we have identified the following portfolio segments: (i) customers for our commodity production and (ii) joint interest partners which are further stratified into the following sub-segments: (a) mutual operators which includes joint interest partners with whom we are a non-operating joint interest partner in properties for which they are the operator, (b) large partners consisting of those legal entities that maintain a working interest of at least 10% in properties for which we are the operator and (c) all others which includes legal entities that maintain working interests of less than 10% in properties for which we are the operator as well as legal entities with whom we no longer have an active joint interest relationship, but continue to have transactions, including joint venture audit settlements, that from time-to-time give rise to the origination of new accounts receivable.

Share-Based Compensation

Our stock compensation plans permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. We measure the cost of employee services received in exchange for an award of equity-classified instruments based on the grant-date fair value of the award. Compensation cost associated with equity-classified awards are generally amortized on a straight-line basis over the applicable vesting period except for those that are based on performance which are amortized on a graded basis over the term of the applicable performance periods. Compensation cost associated with liability-classified awards is measured at the end of each reporting period and recognized based on the period of time that has elapsed during the applicable performance period. We recognize forfeitures as they occur. We recognize share-based compensation expense related to our share-based compensation plans as a component of General and administrative expenses ("G&A") in our consolidated statements of operations.

Recent Accounting Pronouncements

We consider the applicability and impact of all Accounting Standard Updates ("ASUs"). ASUs not listed below were assessed and determined to be not applicable.

Recently Issued Accounting Pronouncements Not Yet Adopted

In October 2021, the Financial Accounting Standards Board issued ASU 2021-08, *Business Combinations (Topic 805): ("ASU 2021-08"): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers.* ASU 2021-08 amends Topic 805 to require the acquirer in a business combination to record contract assets and contract liabilities in accordance with *Revenue from Contracts with Customers (Topic 606)* at acquisition as as if it had originated the contract, rather than at fair value. This update is effective for public companies beginning after December 15, 2022, with early adoption permitted. Adoption should be applied prospectively to business combinations occurring on or after the effective date of the amendments unless early adoption occurs during an interim period in which other application rules apply. We do not expect the adoption of this update to have a material impact to our financial statements.

Note 4 – Transactions

Acquisition of Lonestar Resources

As discussed in Note 1, on October 5, 2021, the Company completed its acquisition of Lonestar in an all-stock transaction. In accordance with the terms of the Merger Agreement, Lonestar shareholders received 0.51 shares of Penn Virginia common stock for each share of Lonestar common stock held immediately prior to the effective time of the Lonestar Acquisition. Based on the closing price of Penn Virginia common stock on October 5, 2021 of $30.19, and in connection with the Lonestar Acquisition, the total value of Penn Virginia common stock issued to holders of Lonestar common stock, warrants and restricted stock units as applicable, was approximately $173.6 million.

In connection with the consummation of the Lonestar Acquisition, the net proceeds from the offering of the 9.25% Senior Notes due 2026 and certain additional funds totaling $411.5 million were released from escrow on the Closing Date. Obligations under the 9.25% Senior Notes due 2026 were assumed by Penn Virginia Holdings, LLC, a Delaware limited liability company ("Holdings"), as borrower, and are guaranteed by the subsidiaries of Holdings that guarantee the Credit Facility.

The net proceeds from the 9.25% Senior Notes due 2026 were used to repay and discharge $249.8 million of Lonestar's long-term debt including accrued interest and related expenses, and the remainder, along with cash on hand, of $146.2 million was used to repay the Second Lien Term Loan including a prepayment premium and accrued interest and related expenses. See Note 9 for additional information on our debt.

The Lonestar Acquisition was accounted for using the acquisition method of accounting, with Ranger Oil being treated as the accounting acquirer. Under the acquisition method of accounting, the assets and liabilities of Lonestar and its subsidiaries was recorded at their respective fair values as of the date of completion of the Lonestar Acquisition and are reflected in the Company's balance sheet as of December 31, 2021. The purchase price allocation is substantially complete; however, it may be subject to change for up to one year subsequent to the closing date of the Lonestar Acquisition. Determining the fair value of the assets and liabilities of Lonestar requires judgment and certain assumptions to be made, the most significant of these being related to the valuation of Lonestar's oil and gas properties. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate.

The following table sets forth the Company’s preliminary allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

		Preliminary Purchase Price Allocation
Consideration:		
Fair value of the Company’s common stock issued [1]	$	173,576
Less: Replacement awards attributable to post-combination compensation cost [2]		(10,394)
Total consideration transferred	$	163,182
Assets:		
Other current assets	$	50,044
Proved oil and gas properties		476,743
ARO asset		1,239
Corporate office building and related assets [3]		11,400
Other property and equipment		2,582
Other non-current assets		37
Total assets acquired	$	542,045
Liabilities:		
Current portion of long-term debt	$	24,187
Other current liabilities		66,150
Derivative liabilities [4]		49,554
Asset retirement obligations		2,494
Long-term debt		236,478
Total liabilities assumed	$	378,863
Net Assets Acquired	$	163,182

1 Includes the fair value of the replacement equity awards to the extent services were provided by employees of Lonestar prior to closing of $ 4.5 million. See Note 16 for additional information about the replacement equity awards.

2 Represents the fair value of the replacement equity awards considered post-combination services. See Note 16 for further details.

3 As of December 31, 2021, these assets met the held for sale criteria and were classified as Assets held for sale on the respective consolidated balance sheet.

4 Immediately following the Lonestar Acquisition, we paid approximately $ 50 million to restructure certain of Lonestar’s derivatives which were novated or terminated. We reset the majority of the swaps to reflect then current market pricing.

For the period from the closing date of the Lonestar Acquisition on October 5, 2021 through December 31, 2021, approximately $62.5 million of revenues and $34.0 million of direct operating expenses were included in the Company’s consolidated statement of operations for the year ended December 31, 2021.

Lonestar Acquisition-Related Expenses

The following table summarizes expenses related to the Lonestar Acquisition incurred for the year ended December 31, 2021:

	Year Ended December 31, 2021
Bank, legal and consulting fees	$ 9,856
Employee severance and related costs	7,563
Replacement awards stock-based compensation costs	10,394
Integration and rebranding costs	1,746
Total acquisition-related expenses	$ 29,559

Employee severance and related costs primarily related to one-time severance and change-in-control compensation costs. Replacement awards stock-based compensation costs related to the accelerated vesting of certain Lonestar share-based awards for former Lonestar employees and directors based on the terms of the Merger Agreement and existing change-in-control provisions within the former Lonestar employment agreements.

Pro Forma Operating Results (Unaudited)

The following unaudited pro forma condensed financial data for the years ended December 31, 2021 and 2020 was derived from the historical financial statements of the Company giving effect to the Lonestar Acquisition, as if it had occurred on January 1, 2020. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for Lonestar's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert Lonestar's outstanding shares of common stock and equity awards as of the closing date of the Lonestar Acquisition, (ii) the depletion of Lonestar's fair-valued proved oil and natural gas properties under the full cost accounting method as well as other impacts of converting Lonestar from successful efforts to the full cost accounting method and (iii) the estimated tax impacts of the pro forma adjustments. The pro forma results of operations do not include any cost savings or other synergies that may result from the Lonestar Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the Lonestar assets.

The pro forma consolidated statements of operations data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Lonestar Acquisition taken place on January 1, 2020 and is not intended to be a projection of future results.

	December 31,	
	2021	2020
Total revenues	$ 729,026	$ 389,495
Net income (loss) attributable to common shareholders	$ 74,355	$ (321,951)

Juniper Transactions

On January 15, 2021 (the "Juniper Closing Date"), the Company consummated the transactions (collectively, the "Juniper Transactions") contemplated by: (i) the Contribution Agreement, dated November 2, 2020 (the "Contribution Agreement"), by and among the Company, PV Energy Holdings, L.P. (the "Partnership") and JSTX Holdings, LLC ("JSTX"), an affiliate of Juniper Capital Advisors, L.P. ("Juniper Capital" and, together with JSTX and Rocky Creek, "Juniper"); and (ii) the Contribution Agreement, dated November 2, 2020 (the "Asset Agreement," and, together with the Contribution Agreement, the "Juniper Transaction Agreements"), by and among Rocky Creek Resources, LLC, an affiliate of Juniper Capital ("Rocky Creek"), the Company and the Partnership.

In connection with the consummation of the Juniper Transactions, the Company completed a reorganization into an up-C structure which was intended to, among other things, result in the affiliates of Juniper Capital having a voting interest in the Company that is commensurate with such holders' economic interest in the Partnership, including (i) the conversion of each of the Company's corporate subsidiaries into limited liability companies which are disregarded for U.S. federal income tax purposes, including the conversion of Penn Virginia Holding Corp. into Holdings, and (ii) the Company's contribution of all of its equity interests in Holdings to the Partnership in exchange for 15,268,686 newly issued common units representing limited partner interests (the "Common Units"). Following consummation of this reorganization, the parent company, Ranger Oil Corporation, and the Partnership are holding companies with no other operations, material cash flows, or material assets or liabilities other than the equity interests in Holdings.

On the Juniper Closing Date, (i) pursuant to the terms of the Contribution Agreement, JSTX contributed to the Partnership, as a capital contribution, $150 million in cash in exchange for 17,142,857 newly issued Common Units and the Company issued to JSTX 171,428.57 shares of Series A Preferred Stock, par value $0.01 per share, of the Company ("Series A Preferred Stock") (now Class B Common Stock as discussed below) at a price equal to the par value of the shares acquired, and (ii) pursuant to the terms of the Asset Agreement, including certain closing adjustments based on a September 1, 2020 effective date (the "Effective Date"), Rocky Creek contributed to our operating subsidiary certain oil and gas assets in exchange for 5,405,252 newly issued Common Units and the Company issued to Rocky Creek 54,052.52 shares of Series A Preferred Stock (5,406,141 Common Units and 54,061.41 shares of Series A Preferred Stock after post-closing adjustments) at a price equal to the par value of the shares acquired, including 495,900 Common Units and 4,959 shares of Series A Preferred Stock placed in a restricted account to support post-closing indemnification claims, 50% of such amount of which was disbursed 180 days after the Juniper Closing Date and the remainder was disbursed one year after the Juniper Closing Date. In connection with the contribution of the oil and gas assets under the Asset Agreement, we received $1.2 million of revenues attributable to production from the Rocky Creek assets for the period from December 1, 2020 through the Juniper Closing Date.

We incurred a total of $19.0 million of professional fees, including advisory, legal, consulting fees and other costs in connection with the Juniper Transactions. A total of $5.0 million were attributable to services and costs incurred and recognized in 2020 as G&A. The remaining $14.0 million of costs were incurred in January 2021 or otherwise incurred contingent upon the closing of the Juniper Transactions, including $5.5 million of transaction costs incurred by Juniper that were required to be paid by the Company under the Juniper Transaction Agreements as well as $3.8 million of costs incurred by us related to the issuance of the Series A Preferred Stock and Common Units. Collectively, these amounts were classified as a reduction to the capital contribution on our consolidated balance sheets. The remainder of $4.7 million, representing professional fees and other costs, was recognized as a component of G&A in the quarter ended March 31, 2021.

In determining the appropriate accounting for the Partnership and Juniper's interest, we considered the guidance in ASC Topic 810, *Consolidation*. The Partnership is considered a variable interest entity for which the Company is the primary beneficiary as it has a controlling financial interest in the Partnership and has the power to direct the activities most significant to the Partnership's economic performance, as well as the obligation to absorb losses and receive benefits that are potentially significant. As such, the Partnership is reflected as a consolidated subsidiary in the consolidated financial statements. The ownership interest in the Partnership held by Juniper (the "Noncontrolling interest") is included in the consolidated balance sheets as Noncontrolling interest, which is classified within permanent equity. The Noncontrolling interest is classified in permanent equity as it does not meet the definition of a liability under ASC 480, *Distinguishing Liabilities from Equity* and, among other considerations, the Common Units are optionally redeemable by the holder for a fixed number of shares (on a one-for-one basis) and there is no fixed or determinable date or fixed or determinable price for redemption; further, while the Common Units may be redeemed with Class A Common Stock or cash, the method of settlement is solely at the discretion of the Company, with the Company having the ability to settle the redemption in shares. Additionally, while the holders of the Series A Preferred Stock, who also own the Common Units, could cause the Noncontrolling interest to be redeemed through an event that is not solely within the control of the Company such as a change-in-control, through their majority voting rights, all holders of equally and more subordinated equity interests in the Company would be entitled to receive the same form of consideration upon such event.

The Noncontrolling interest percentage is based on the proportionate amount of the number of Common Units held by Juniper to the total Common Units outstanding which is also equivalent to the voting power in the Company associated with the Series A Preferred Stock held by Juniper. The Noncontrolling interest was initially measured on the Juniper Closing Date as the sum of (i) total Shareholders' equity immediately prior to the closing of the Juniper Transactions, (ii) the fair value of Juniper's and Rocky Creek's contributions provided in exchange for Common Units and Series A Preferred Stock (net of the Juniper transaction costs and securities issuance costs paid by the Company and including the cash received directly by the Company for a portion of the Rocky Creek revenues as discussed above and AROs associated with the contributed properties); and (iii) a deferred income tax adjustment attributable to the Juniper Transactions, the total of which was then multiplied by the Noncontrolling interest percentage. The difference between the calculated Noncontrolling interest and the fair value of the consideration received was recorded as a reduction to paid-in capital.

On October 6, 2021, the Company, JSTX and Rocky Creek entered into a Contribution and Exchange Agreement, whereby all outstanding shares of the Series A Preferred Stock were exchanged for newly issued shares of Class B Common Stock ("Class B Common Stock"), at a ratio of one share of Class B Common Stock for each 1/100th of a share of Series A Preferred Stock and the designation of the Series A Preferred Stock was cancelled. See Note 15 for additional information.

The following table reconciles the initial investment by Juniper and the carrying value of their Noncontrolling interest as of the Juniper Closing Date (after post-closing adjustments):

Cash contribution	$	150,000
Issue costs paid for Noncontrolling interest securities		(3,758)
Transaction costs paid on behalf of Noncontrolling interest		(5,543)
Fair value of Rocky Creek oil and gas properties contributed		38,561
Revenues received attributable to contributed properties		1,160
Suspense revenues attributable to the contributed properties		(146)
Asset retirement obligations of the contributed properties		(14)
Fair value of capital contributions		180,260
Income tax adjustment attributable to the Juniper Transactions		(708)
Total shareholders' equity prior to the Juniper Closing Date		205,558
	$	385,110
Juniper voting power through Series A Preferred Stock		59.6 %
Noncontrolling interest as of the Juniper Closing Date	$	229,620

Due to the Lonestar Acquisition in October 2021, a change in ownership of the Noncontrolling interest occurred. Refer to Note 17 for additional information.

Eagle Ford Working Interests

In 2019, we acquired working interests in certain properties for which we are the operator from our joint venture partners in a series of transactions for cash consideration of $6.5 million. Funding for these acquisitions was provided by borrowings under the Credit Facility.

Note 5 – Revenue Recognition

The Company's revenues are derived from contracts for crude oil, natural gas and NGL sales and other services, as described in Note 3.

Our accounts receivable consists mainly of trade receivables from commodity sales and joint interest billings due from partners on properties we operate. Our allowance for credit losses is entirely attributable to receivables from joint interest partners. We generally have the right to withhold future revenue distributions to recover past due receivables from joint interest owners. Generally, our oil, natural gas, and NGL receivables are collected within 30 to 90 days. The following table summarizes our accounts receivable by type as of the dates presented:

	December 31,	
	2021	2020
Customers	$ 96,195	$ 39,672
Joint interest partners	21,755	3,079
Derivative settlements from counterparties	1,037	3,287
Other	18	8
Total	119,005	46,046
Less: Allowance for credit losses	(411)	(197)
Accounts receivable, net of allowance for credit losses	$ 118,594	$ 45,849

Major Customers

For the year ended December 31, 2021, three customers accounted for 48% of our consolidated product revenues, of which 22%, 14%, and 12% of the consolidated revenues were generated from these customers, respectively. For the year ended December 31, 2020, three customers accounted for 56% of our consolidated product revenues, of which 27%, 19%, and 10% of the consolidated revenues were generated from these customers, respectively. For the year ended December 31, 2019, four customers accounted for 76% of our consolidated product revenues of which 37%, 18%, 11%, and 10% of the consolidated revenues were generated from these customers, respectively.

Note 6 – Derivative Instruments

We utilize derivative instruments, typically swaps, put options and call options which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. Our derivative instruments are not formally designated as hedges for accounting purposes. While the use of derivative instruments limits the risk of adverse commodity price and interest rate movements, such use may also limit the beneficial impact of future product revenues and interest expense from favorable commodity price and interest rate movements. From time to time, we may enter into incremental derivative contracts in order to increase the notional volume of production we are hedging, restructure existing derivative contracts or enter into other derivative contracts resulting in modification to the terms of existing contracts. In accordance with our internal policies, we do not utilize derivative instruments for speculative purposes.

For our commodity derivatives, we typically combine swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging objectives. Certain of these objectives result in combinations that operate as collars which include purchased put options and sold call options, three-way collars, which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap, among others.

Commodity Derivatives

The following is a general description of the commodity derivative instruments we employ:

Swaps. A swap contract is an agreement between two parties pursuant to which the parties exchange payments at specified dates on the basis of a specified notional amount, or the swap price, with the payments calculated by reference to specified commodities or indexes. The purchasing counterparty to a swap contract is required to make a payment to selling counterparty based on the amount of the swap price in excess of the settlement price multiplied by the notional volume if the settlement price for any settlement period is below the swap price for such contract. We are required to make a payment to the counterparty based on the amount of the settlement price in excess of the swap price multiplied by the notional volume if the settlement price for any settlement period is above the swap price for such contract.

Put Options. A put option has a defined strike, or floor price. We have entered into put option contracts in the roles of buyer and seller depending upon our particular hedging objective. The buyer of the put option pays the seller a premium to enter into the contract. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the notional volume. When the settlement price is above the floor price, the put option expires worthless. Certain of our purchased put options have deferred premiums. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement.

Call Options. A call option has a defined strike, or ceiling price. We have entered into call option contracts in the roles of buyer and seller depending upon our particular hedging objective. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the notional volume. When the settlement price is below the ceiling price, the call option expires worthless.

Two-Way Collars. A two-way collar is an arrangement that contains a sold call option, which establishes a maximum price (ceiling price) we will receive for the contract volumes, and a purchased put, which establishes a minimum price (floor price) we will receive based on an index price. We have entered into two-way collars periodically to achieve particular hedging objectives. When the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price. If the index price is between the floor and ceiling prices, no payments are due from either party. When the index price is below the floor price, we will receive the difference between the floor price and the index price.

The following table sets forth our commodity derivative contracts as of December 31, 2021:

Commodity Derivatives	1Q2022	2Q2022	3Q2022	4Q2022	1Q2023	2Q2023	3Q2023	4Q2023	1Q2024	2Q2024
NYMEX WTI Crude Swaps										
Average Volume Per Day (bbl)	3,250	3,000	3,000	3,000	2,500	2,400	2,807	2,657	462	462
Weighted Average Swap Price ($/bbl)	$ 75.16	$ 74.12	$ 73.01	$ 69.20	$ 54.40	$ 54.26	$ 54.92	$ 54.93	$ 58.75	$ 58.75
NYMEX WTI Crude Collars										
Average Volume Per Day (bbl)	17,083	14,423	7,745	6,114	2,917	2,885				
Weighted Average Purchased Put Price ($/bbl)	$ 56.10	$ 54.29	$ 47.37	$ 45.33	$ 40.00	$ 40.00				
Weighted Average Sold Call Price ($/bbl)	$ 70.49	$ 72.84	$ 64.60	$ 60.87	$ 50.00	$ 50.00				
NYMEX WTI Purchased Puts										
Average Volume Per Day (bbl)	9,444									
Weighted Average Purchased Put Price ($/bbl)	$ 65.74									
NYMEX WTI Crude CMA Roll Basis Swaps										
Average Volume Per Day (bbl)	13,333	13,187	6,522	6,522						
Weighted Average Swap Price ($/bbl)	$ 0.880	$ 0.880	$ 1.135	$ 1.135						
NYMEX HH Swaps										
Average Volume Per Day (MMBtu)	17,500	12,500	12,500	12,500	10,000	7,500				
Weighted Average Swap Price ($/MMBtu)	$ 4.349	$ 3.727	$ 3.745	$ 3.793	$ 3.620	$ 3.690				
NYMEX HH Collars										
Average Volume Per Day (MMBtu)	3,333	13,187	13,043	13,043		11,538	11,413	11,413	11,538	11,538
Weighted Average Purchased Put Price ($/MMBtu)	$ 4.150	$ 2.500	$ 2.500	$ 2.500		$ 2.500	$ 2.500	$ 2.500	$ 2.500	$ 2.328
Weighted Average Sold Call Price ($/MMBtu)	$ 5.750	$ 3.220	$ 3.220	$ 3.220		$ 2.682	$ 2.682	$ 2.682	$ 3.650	$ 3.000
OPIS Mt Belv Ethane Swaps										
Average Volume per Day (gal)		28,022	27,717	27,717		98,901	34,239	34,239	34,615	
Weighted Average Fixed Price ($/gal)		$ 0.2500	$ 0.2500	$ 0.2500		$ 0.2288	$ 0.2275	$ 0.2275	$ 0.2275	

Interest Rate Derivatives

As of December 31, 2021, we had a series of interest rate swap contracts (the "Interest Rate Swaps") establishing fixed interest rates on a portion of our variable interest rate indebtedness. The notional amount of the Interest Rate Swaps totals $300 million, with us paying a weighted average fixed rate of1.36% on the notional amount, and the counterparties paying a variable rate equal to LIBOR through May 2022.

Financial Statement Impact of Derivatives

The impact of our derivatives activities on income is included within Derivatives on our consolidated statements of operations. Derivative contracts that have expired at the end of a period, but for which cash had not been received or paid as of the balance sheet date, have been recognized as components of Accounts receivable (see Note 5) and Accounts payable and accrued liabilities (see Note 12) on the consolidated balance sheets. The effects of derivative gains and (losses) and cash settlements are reported as adjustments to reconcile net income (loss) to net cash provided by operating activities. These items are recorded within the Derivative contracts section of our consolidated statements of cash flows under Net (gains) losses and Cash settlements and premiums received (paid), net.

The following table summarizes the effects of our derivative activities for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Interest Rate Swap losses recognized in the consolidated statements of operations	$ (2)	$ (7,510)	$ —
Commodity gains (losses) recognized in the consolidated statements of operations	(136,997)	95,932	(68,131)
	$ (136,999)	$ 88,422	$ (68,131)
Interest rate cash settlements recognized in the consolidated statements of cash flows	$ (3,822)	$ (2,210)	$ —
Commodity cash settlements and premiums received (paid) recognized in the consolidated statements of cash flows	(77,099)	80,297	(4,136)
Commodity cash settlements paid for acquired derivatives recognized in the consolidated statements of cash flows	(49,554)	—	—
	$ (130,475)	$ 78,087	$ (4,136)

The following table summarizes the fair value of our derivative instruments, which we elect to present on gross basis, as well as the locations of these instruments on our consolidated balance sheets as of the dates presented:

		Fair Values			
		December 31, 2021		December 31, 2020	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Interest rate contracts	Derivative assets/liabilities – current	$ —	$ 1,480	$ —	$ 3,655
Commodity contracts	Derivative assets/liabilities – current	11,478	48,892	75,506	81,451
Interest rate contracts	Derivative assets/liabilities – non-current	—	—	—	1,645
Commodity contracts	Derivative assets/liabilities – non-current	2,092	23,815	25,449	26,789
		$ 13,570	$ 74,187	$ 100,955	$ 113,540

As of December 31, 2021, we reported net commodity derivative liabilities of $59.1 million and net Interest Rate Swap liabilities of $1.5 million. The contracts associated with these positions are with eight counterparties for commodity derivatives and four counterparties for Interest Rate Swaps, all of which are investment grade financial institutions and are participants in the Credit Facility. This concentration may impact our overall credit risk in that these counterparties may be similarly affected by changes in economic or other conditions. Non-performance risk is incorporated by utilizing discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position.

The agreements underlying our derivative instruments include provisions for the netting of settlements with the counterparties for contracts of similar type. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

See Note 13 for information regarding the fair value of our derivative instruments.

Note 7 – Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	December 31, 2021	December 31, 2020
Oil and gas properties:		
Proved	$ 2,327,686	$ 1,545,910
Unproved	57,900	49,935
Total oil and gas properties	2,385,586	1,595,845
Other property and equipment [1]	31,055	27,746
Total properties and equipment	2,416,641	1,623,591
Accumulated depreciation, depletion, amortization and impairments	(1,033,293)	(900,042)
Total property and equipment, net	$ 1,383,348	$ 723,549

[1] Excludes the corporate office building and related assets acquired in connection with the Lonestar Acquisition that were classified as Assets held for sale on the consolidated balance sheets as of December 31, 2021.

Unproved property costs of $57.9 million and $49.9 million have been excluded from amortization as of December 31, 2021 and December 31, 2020, respectively. An additional $1.2 million of costs, associated with wells in-progress for which we had not previously recognized any proved undeveloped reserves, were excluded from amortization as of December 31, 2020. The total costs not subject to amortization as of December 31, 2021 were incurred in the following periods: $8.4 million in 2021, $0.7 million in 2020, zero in 2019 and $37.3 million prior to 2018 as well as $11.5 million of capitalized interest applied thereto. We transferred $17.8 million and $8.3 million of undeveloped leasehold costs, including capitalized interest, associated with proved undeveloped reserves, acreage unlikely to be drilled or expiring acreage, from unproved properties to the full cost pool during the years ended December 31, 2021 and 2020, respectively. We capitalized internal costs of $4.1 million, $2.1 million and $4.1 million and interest of $3.6 million, $2.7 million and $4.1 million during the years ended December 31, 2021, 2020 and 2019 respectively, in accordance with our accounting policies. Average DD&A per boe of proved oil and gas properties was $12.96, $15.83 and $17.25 for the years ended December 31, 2021, 2020 and 2019, respectively.

Certain events such as the novel coronavirus ("COVID-19") pandemic and the decisions by the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (together with OPEC, collectively "OPEC+") have negatively impacted the oil and gas industry with significant declines in crude oil prices and oversupply of crude oil and may continues to negatively affect our business. Because the Ceiling Test utilizes commodity prices based on a trailing 12 month average, the decline in commodity prices as a result of COVID-19 and macroeconomic factors resulted in impairments of our oil and gas properties of $1.8 million and $391.8 million, respectively, during the years ended December 31, 2021 and 2020. We did not record any impairments of its oil and gas properties during the year ended December 31, 2019.

Note 8 – Asset Retirement Obligations

The following table reconciles our AROs as of the dates presented, which are included within Other liabilities on our consolidated balance sheets:

	Year Ended December 31, 2021	Year Ended December 31, 2020
Balance at beginning of period	$ 5,461	$ 4,934
Changes in estimates	—	33
Liabilities incurred	226	121
Liabilities settled	(228)	—
Acquisitions of properties	2,508	16
Accretion expense	446	357
Balance at end of period	$ 8,413	$ 5,461

Note 9 – Long-Term Debt

The following table summarizes our long-term debt as of the dates presented:

	December 31, 2021	December 31, 2020
Credit Facility	$ 208,000	$ 314,400
Second Lien Term Loan	—	200,000
9.25% Senior Notes due 2026	400,000	—
Mortgage debt [1]	8,438	—
Other [2]	2,516	—
Total	618,954	514,400
Less: Unamortized discount [3]	(3,720)	(1,604)
Less: Unamortized deferred issuance costs [3, 4]	(9,853)	(3,299)
Total, net	$ 605,381	$ 509,497
Less: Current portion	(4,129)	—
Long-term debt, net	$ 601,252	$ 509,497

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1 The mortgage debt relates to the corporate office building and related assets acquired in connection with the Lonestar Acquisition for which assets are held as collateral for such debt. As of December 31, 2021, these assets met the held for sale criteria and were classified as Assets held for sale on the consolidated balance sheets.

2 Other includes approximately $2.2 million related to a PPP loan assumed in the Lonestar Acquisition which was fully forgiven subsequent to December 31, 2021.

3 Prior to the repayment of the Second Lien Term Loan as discussed below, discount and issuance costs of the Second Lien Term Loan were amortized over the term of the underlying loan using the effective-interest method. The discount and issuance costs of the 9.25% Senior Notes due 2026 are being amortized over its respective term using the effective-interest method.

4 Excludes issuance costs associated with the Credit Facility, which represent costs attributable to the access to credit over its contractual term, that have been presented as a component of Other assets (see Note 12) and are being amortized over the term of the Credit Facility using the straight-line method.

Credit Facility

As of December 31, 2021, the Credit Facility had a $1.0 billion revolving commitment and a $725 million borrowing base, with aggregate elected commitments of $400 million, and a $25 million sublimit for the issuance of letters of credit. Availability under the Credit Facility may not exceed the lesser of the aggregate elected commitments or the borrowing base less outstanding advances and letters of credit; The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes, including working capital.

In August 2021, we entered into the Master Assignment, Agreement and Amendment No. 11 to Credit Agreement (the "Eleventh Amendment"). The Eleventh Amendment, in addition to other changes described therein, amended the Credit Facility to, effective on the closing of the Lonestar Acquisition and satisfaction of other conditions set forth therein, (1) increase the borrowing base from $375 million to $600 million, with aggregate elected commitments of $400 million, (2) remove certain availability restrictions, (3) remove minimum hedging requirements, (4) remove the first lien leverage ratio covenant, (5) remove the Partnership and PV Energy Holdings GP, LLC as guarantors, and (6) extend the maturity date from May 2024 to the date that is the four year anniversary of the date such amendment became effective, or October 6, 2025. Subsequent to the Eleventh Amendment, the borrowing base was further increased to $725 million effective December 31, 2021, with aggregate elected commitments remaining at $400 million.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a Eurodollar rate, including LIBOR through 2023, plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on Eurodollar borrowings is payable every one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days. As of December 31, 2021, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.26%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00 and (2) a maximum leverage ratio (consolidated indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 3.50 to 1.00.

The Credit Facility also contains other customary affirmative and negative covenants as well as events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of December 31, 2021 and 2020, we had $0.9 million and $0.4 million in letters of credit outstanding under the Credit Facility. In the years ended December 31, 2021 and 2020, we incurred and capitalized issue costs of $2.6 million and $0.1 million, respectively, in connection with amendments to the Credit Facility. Additionally, during 2021, we wrote off $0.8 million of previously deferred debt issue costs associated with the Eleventh Amendment and during 2020, we wrote off $0.9 million of previously deferred debt issue costs due to a decrease in the borrowing base associated with an amendment during the first half of 2020.

Second Lien Term Loan

We entered into the $200 million Second Lien Term Loan in September 2017 to fund a significant acquisition as well as related fees and expenses. In January 2021, the amendment dated November 2, 2020 (the "Second Lien Amendment") became effective at which time we made a $50.0 million prepayment as well as a $1.3 million principal payment to a single participant lender to liquidate their interest in the Second Lien Term Loan. The Second Lien Amendment provided for (i) the extension of the maturity date of the Second Lien Term Loan to September 29, 2024, (ii) an increase to the margin applicable to advances under the Second Lien Term Loan; (iii) the imposition of certain limitations on capital expenditures, acquisitions and investments if the Asset Coverage Ratio (as defined therein) at the end of any fiscal quarter is less than 1.25 to 1.00, (iv) the requirement for maximum and, in certain circumstances as described therein, minimum hedging arrangements, (v) beginning in 2021, a requirement to make quarterly amortization payments equal to $1.875 million and (vi) a provision for the replacement of the LIBOR interest rate upon its expiration. During 2021, we incurred and capitalized $1.4 million of issue costs in connection with the Second Lien Amendment and wrote off $1.2 million of previously capitalized issue costs and original issue discount allocable to the aforementioned prepayments as a loss on extinguishment of debt.

The outstanding borrowings under the Second Lien Term Loan bore interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin of 7.25% or (b) a Eurodollar rate, including LIBOR, with a floor of 1.00%, plus an applicable margin of 8.25%; provided that the applicable margin would increase to 8.25% and 9.25%, respectively, during any quarter in which the quarterly amortization payment was not made. Interest on reference rate borrowings was payable quarterly in arrears and computed on the basis of a year of 365/366 days, and interest on Eurodollar borrowings was payable every one or three months (including in three month intervals if we select a six-month interest period), at our election and computed on the basis of a 360-day year.

The Second Lien Term Loan was collateralized by substantially all of our operating subsidiaries' assets with lien priority subordinated to the liens securing the Credit Facility.

On October 5, 2021, Holdings repaid all of its outstanding obligations under the Second Lien Term Loan and terminated the Second Lien Term Loan. In accordance with the Second Lien Term Loan, we incurred a prepayment premium of 102% as a result of repayment. In connection with the repayment of the Second Lien Term Loan, we incurred costs related to the premium and write off of unamortized discount and issuance costs of $6.9 million recorded as a loss on extinguishment of debt.

9.25% Senior Notes due 2026

On August 10, 2021, our indirect, wholly-owned subsidiary Penn Virginia Escrow LLC (the "Escrow Issuer") completed an offering of $400 million aggregate principal amount of senior unsecured notes due 2026 (the "9.25% Senior Notes due 2026") that bear interest at 9.25% and were sold at 99.018% of par. The proceeds of the offering, net of discount, and other funds were initially deposited in an escrow account pending satisfaction of certain conditions, including the consummation of the Lonestar Acquisition on or prior to November 26, 2021.

In connection with the consummation of the Lonestar Acquisition, the net proceeds from the offering of the 9.25% Senior Notes due 2026 and certain additional funds totaling $411.5 million were released from escrow on October 5, 2021. Obligations under the 9.25% Senior Notes due 2026 were assumed by Holdings, as borrower, and are guaranteed by the subsidiaries of Holdings that guarantee the Credit Facility.

The net proceeds from the 9.25% Senior Notes due 2026 were used to repay and discharge $249.8 million of Lonestar's long-term debt including accrued interest and related expenses, and the remainder, along with cash on hand, of $146.2 million was used to repay the Second Lien Term Loan including a prepayment premium and accrued interest and related expenses. During 2021, we incurred and capitalized $10.4 million of issue costs in connection with the 9.25% Senior Notes due 2026. See Note 4 for additional information.

The indenture governing the 9.25% Senior Notes due 2026 (the "Indenture") also contains other customary affirmative and negative covenants as well as events of default and remedies.

As of December 31, 2021, the Company was in compliance with all debt covenants.

Note 10 – Income Taxes

The following table summarizes our provision for income taxes for the periods presented:

	Year Ended December 31, 2021	2020	2019
Current income tax expense (benefit)			
Federal	$ —	$ (1,236)	$ (1,236)
State	311	357	—
Total current income tax expense (benefit)	311	(879)	(1,236)
Deferred income tax expense (benefit)			
Federal	—	1,236	1,236
State	1,249	(2,660)	2,137
Total deferred income tax expense (benefit)	1,249	(1,424)	3,373
Income tax expense (benefit)	$ 1,560	$ (2,303)	$ 2,137

The following table reconciles the difference between the income tax expense (benefit) computed by applying the statutory tax rate to our income (loss) before income taxes and our reported income tax expense (benefit) for the periods presented:

	Year Ended December 31, 2021		2020		2019	
Computed at federal statutory rate	$ 21,100	21.0 %	$ (65,701)	21.0 %	$ 15,272	21.0 %
State income taxes, net of federal income tax benefit	1,560	1.6 %	(1,856)	0.6 %	1,494	2.1 %
Change in valuation allowance	(9,348)	(9.3)%	64,062	(20.5)%	(14,240)	(19.6)%
Noncontrolling interest	(12,501)	(12.4)%	—	— %	—	— %
Other, net	749	0.7 %	1,192	(0.4)%	(389)	(0.5)%
	$ 1,560	1.6 %	$ (2,303)	0.7 %	$ 2,137	3.0 %

The following table summarizes the principal components of our deferred income tax assets and liabilities as of the dates presented:

	December 31,	
	2021	2020
Deferred tax assets:		
Net operating loss ("NOL") carryforwards	$ 203,243	$ 180,531
Asset retirement obligations	63	1,188
Property and equipment	24,585	—
Pension and postretirement benefits	—	301
Share-based compensation	—	467
Fair value of derivative instruments	493	2,737
Interest expense limitation	13,747	—
ROU assets	—	564
Other	18	1,484
Total deferred tax assets	242,149	187,272
Less: Valuation allowance	(205,617)	(179,006)
Total net deferred tax assets	$ 36,532	$ 8,266
Deferred tax liabilities:		
Property and equipment	$ 3,357	$ 7,728
Investment in the Partnership	35,968	—
ROU obligations	—	538
Total deferred tax liabilities	$ 39,325	$ 8,266
Net deferred tax liabilities	$ (2,793)	$ —

Income Tax Provision

For the year ended December 31, 2021, we did not have any current federal tax benefits. The provision for the years ended December 31, 2020 and 2019 includes current federal benefits of $1.2 million and $1.2 million attributable to refunds of AMT credits for the 2020 and 2019 tax years, respectively. The amounts attributable to 2020 combined the amounts attributable to 2019, which had been recognized on our consolidated balance sheets as of December 31, 2019 as a current asset, were received in 2020 as an acceleration of all AMT credits in connection with certain provisions of the CARES Act. In addition, we have recognized deferred state tax expense (benefits) of $ 1.2 million, $(2.7) million and $2.1 million primarily attributable to property and equipment as well as $0.3 million, $0.4 million and zero current state expense attributable to the Texas margin tax for the years ended December 31, 2021, 2020 and 2019, respectively. Our overall effective tax rates were 1.6%, 0.7% and 3.0% for the years ended December 31, 2021, 2020 and 2019, respectively.

Deferred Tax Assets and Liabilities

As of December 31, 2021, we had federal NOL carryforwards of approximately $746.8 million, a substantial portion of which, if not utilized, expire between 2032 and 2037. NOLs incurred after January 1, 2018 can be carried forward indefinitely. Because of the change in ownership provisions of the Code, use of a portion of our federal NOLs may be limited in future periods. As of December 31, 2021, we carried a valuation allowance against our federal and state deferred tax assets of $205.6 million, which includes an increase of $24.8 million related to the Lonestar Acquisition. We considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. The amount of deferred tax assets considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence is no longer present and additional weight is given to subjective positive evidence, including projections for growth. The valuation allowance along with $39.3 million of deferred tax liabilities fully offset our deferred tax assets. The net deferred tax liability recognized on our consolidated balance sheets as of December 31, 2021 is attributable to certain state deferred tax liabilities associated with property and equipment and unrealized hedges. The valuation allowance related to all other net deferred tax assets remains in full as of December 31, 2021 and 2020.

Following the Juniper Transactions, Ranger Oil is a holding company and all of its operating assets are held within the Partnership. Certain of the federal deferred tax assets and liabilities were reclassified to investment in partnership deferred tax liability.

Other Income Tax Matters

We had no liability for unrecognized tax benefits as of December 31, 2021 and 2020. There were no interest and penalty charges recognized during the years ended December 31, 2021, 2020 and 2019. Tax years from 2015 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

Note 11 – Leases

We generally have lease arrangements for office facilities and certain office equipment, certain field equipment including compressors, drilling rigs, crude oil storage tank capacity, land easements and similar arrangements for rights-of-way, and certain gas gathering and gas lift assets. Our short-term leases included in the disclosures below are primarily comprised of our contractual arrangements with certain vendors for operated drilling rigs, crude oil storage tank capacity and our field compressors. Our primary variable lease was represented by our field gas gathering and gas lift agreement with a midstream service provider and the lease payments are charged on a volumetric basis at a contractual fixed rate.

The following table summarizes the components of our total lease cost for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Operating lease cost	$ 891	$ 979	$ 773
Short-term lease cost	24,655	23,721	36,202
Variable lease cost	24,807	21,932	23,762
Less: Amounts charged as drilling costs [1]	(21,213)	(20,708)	(33,354)
Total lease cost recognized in the consolidated statement of operations [2]	$ 29,140	$ 25,924	$ 27,383

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[1] Represents the combined gross amounts paid and (i) capitalized as drilling costs for our working interest share and (ii) billed to joint interest partners for their working interest share for short-term leases of operated drilling rigs.

[2] Includes $10.8 million, $11.2 million and $12.1 million recognized in GPT, $ 17.4 million, $13.8 million and $14.5 million recognized in Lease operating expense ("LOE") and $ 0.9 million, $1.0 million and $0.8 million recognized in G&A for the years ended December 31, 2021, 2020, and 2019, respectively.

The following table summarizes supplemental cash flow information related to leases for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 981	$ 943	$ 659
ROU assets obtained in exchange for operating lease obligations [1]	$ —	$ 388	$ 3,325

[1] Includes $2.5 million recognized upon adoption of ASC Topic 842, *Leases* and $0.8 million obtained during the twelve months ended December 31, 2019.

The following table summarizes supplemental balance sheet information related to leases as of the dates presented:

		December 31,	
Leases	**Balance Sheet Location**	**2021**	**2020**
Assets			
ROU assets – operating leases	Other assets	$ 1,671	$ 2,432
Liabilities			
Current operating lease obligations	Accounts payable and accrued liabilities	$ 914	$ 936
Non-current operating lease obligations	Other non-current liabilities	975	1,752
Total operating lease obligations		$ 1,889	$ 2,688

The following table presents other information as it relates to operating leases as of the dates presented:

	December 31,	
	2021	2020
Weighted-average remaining lease term – operating leases	2.1 years	3.1 years
Weighted-average discount rate – operating leases	3.13 %	3.24 %

As of December 31, 2021, maturities of our operating lease liabilities consisted of the following:

	December 31, 2021
2022	$ 930
2023	878
2024	146
2025	—
2026	—
Total undiscounted lease payments	1,954
Less: imputed interest	(65)
Total operating lease obligations	$ 1,889

Note 12 – Supplemental Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	December 31,	
	2021	2020
Prepaid and other current assets:		
Inventories [1]	$ 10,305	$ 4,274
Prepaid expenses [2]	10,693	14,771
	$ 20,998	$ 19,045
Other assets:		
Deferred issuance costs of the Credit Facility, net of amortization	$ 3,308	$ 2,349
Right-of-use assets – operating leases	1,671	2,432
Other	38	127
	$ 5,017	$ 4,908
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 32,452	$ 7,055
Drilling and other lease operating costs	35,045	16,088
Revenue and royalties payable	95,521	26,615
Production, ad valorem and other taxes	7,905	3,094
Derivative settlements to counterparties	6,117	321
Compensation and benefits	13,942	4,222
Interest	15,321	504
Environmental remediation liability [3]	2,287	—
Current operating lease obligations	914	936
Other [4]	4,877	4,254
	$ 214,381	$ 63,089
Other non-current liabilities:		
Asset retirement obligations	$ 8,413	$ 5,461
Non-current operating lease obligations	975	1,752
Postretirement benefit plan obligations	970	1,149
	$ 10,358	$ 8,362

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[1] Includes tubular inventory and well materials of $9.5 million and $3.9 million and crude oil volumes in storage of $ 0.8 million and $0.4 million as of December 31, 2021 and 2020, respectively.

[2] The balance as of December 31, 2021 and 2020 includes $ 9.6 million and $13.6 million, respectively, for the prepayment of drilling and completion services and materials.

[3] The balance as of December 31, 2021 represents estimated costs associated with remediation activities for certain wells and tanks acquired as part of the Lonestar Acquisition.

[4] The balance as of December 31, 2021 includes liabilities assumed as part of the Lonestar Acquisition of $ 2.5 million. The balance as of December 31, 2020 includes $ 3.5 million of accrued costs attributable to Juniper Transaction expenses.

Note 13 – Fair Value Measurements

We apply the authoritative accounting provisions included in GAAP for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use a hierarchy that prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below.

Fair value measurements are classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Our financial instruments, including cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to their short-term maturities. As of December 31, 2021 and 2020, the carrying values of the borrowings outstanding under our credit facilities approximate fair value as the borrowings bear interest at variables rates tied to current market rates and the applicable margins represent market rates. The fair value of our fixed rate 9.25% Senior Notes due 2026 is estimated based on the published market prices for issuances of similar risk and tenor and is categorized as Level 2 within the fair value hierarchy. As of December 31, 2021, the carrying amount and estimated fair value of total debt (before amortization of issuance costs) was $619.0 million and $634.6 million, respectively. As of December 31, 2020, the estimated fair value of total debt (before amortization of issuance costs) approximated the carrying value of $514.4 million.

Recurring Fair Value Measurements

The fair values of our derivative instruments are measured at fair value on a recurring basis on our consolidated balance sheets. The following tables summarize the valuation of those financial assets and (liabilities) as of the dates presented:

	As of December 31, 2021			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity derivative assets – current	$ —	$ 11,478	$ —	$ 11,478
Commodity derivative assets – non-current	—	2,092	—	2,092
Total financial assets	$ —	$ 13,570	$ —	$ 13,570
Financial liabilities:				
Interest rate swap liabilities – current	$ —	$ (1,480)	$ —	$ (1,480)
Commodity derivative liabilities – current	—	(48,892)	—	(48,892)
Commodity derivative liabilities – non-current	—	(23,815)	—	(23,815)
Total financial liabilities	$ —	$ (74,187)	$ —	$ (74,187)

	As of December 31, 2020			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity derivative assets – current	$ —	$ 75,506	$ —	$ 75,506
Commodity derivative assets – non-current	—	25,449	—	25,449
Total financial assets	$ —	$ 100,955	$ —	$ 100,955
Financial liabilities:				
Interest rate swap liabilities – current	$ —	$ (3,655)	$ —	$ (3,655)
Interest rate swap liabilities – non-current	—	(1,645)	—	(1,645)
Commodity derivative liabilities – current	—	(81,451)	—	(81,451)
Commodity derivative liabilities – non-current	—	(26,789)	—	(26,789)
Total financial liabilities	$ —	$ (113,540)	$ —	$ (113,540)

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatilities, time value and non-performance risk. For the current market prices, we use third-party quoted forward prices, as applicable, for NYMEX WTI, MEH crude oil and NYMEX HH natural gas and OPIS Mt Belv Ethane natural gas liquids closing prices as of the end of the reporting periods. Each of these is a level 2 input.

- *Interest rate swaps*: We determine the fair values of our interest rate swaps using an income valuation approach valuation technique which discounts future cash flows back to a single present value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a Level 2 input.

Non-performance risk is incorporated by utilizing discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position. See Note 6 for additional details on our derivative instruments.

Non-Recurring Fair Value Measurements

In addition to the fair value measurements applied with respect to assets contributed in the Juniper Transactions and acquired with the Lonestar Acquisition, as described in Note 4, the most significant non-recurring fair value measurements utilized in the preparation of our consolidated financial statements are those attributable to the initial determination of AROs associated with the ongoing development of new oil and gas properties and certain share-based compensation awards. The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as level 3 inputs.

Note 14 – Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2021, by category, for the next5 years and thereafter:

Year	Gathering and Intermediate Transportation Commitments	Other Commitments
2022	$ 13,937	$ 380
2023	13,937	143
2024	13,976	56
2025	13,937	—
2026	7,794	—
Thereafter	15,808	—
Total	$ 79,389	$ 579

Drilling and Completion Commitments

As of December 31, 2021, we had contractual commitments on a pad-to-pad basis fortwo drilling rigs.

Gathering and Intermediate Transportation Commitments

We have long-term agreements that provide us with field gathering and intermediate pipeline transportation services for a majority of our crude oil and condensate production in Lavaca and Gonzales Counties, Texas. We also have volume capacity support for certain downstream interstate pipeline transportation. The following table provides details on these contractual arrangements as of December 31, 2021:

Description of contractual arrangement	Expiration of Contractual Arrangement	Minimum Volume Delivery (bbl/d)	Expiration of Minimum Volume Commitment
Field gathering agreement	February 2041	8,000	February 2031
Intermediate pipeline transportation services	February 2026	8,000	February 2026
Volume capacity support	April 2026	8,000	April 2026

Each of these arrangements also contain an obligation to deliver the first20,000 gross barrels of oil per day produced from Gonzales, Lavaca, Fayette and DeWitt Counties, Texas. For certain of our crude oil volumes gathered under the field gathering agreement, our rate includes an adjustment based on NYMEX WTI prices. As crude oil prices increase, up to a cap of $90 per bbl, the gathering rate escalates pursuant to the field gathering agreement.

Under each of the arrangements, credits for deliveries of volumes in excess of the volume commitment may be applied to any deficiency arising in the succeeding 12-month period.

During the years ended December 31, 2021, 2020 and 2019, we recorded expense of $36.0 million, $34.5 million and $31.9 million, respectively, for these contractual obligations in connection with these arrangements.

Crude Oil Storage

As a component of the crude oil gathering agreement referenced above, we have access to approximately180,000 barrels of dedicated tank capacity for no additional charge at the service provider's central delivery point facility ("CDP"), in Lavaca County, Texas through February 2041. In addition, we have access for up to a maximum of 340,000 barrels of tank capacity through April 2022 and evergreen month-to-month at several locations in the South Texas region. We have also contracted for access to an additional 70,000 barrels of tank capacity at the CDP on a month-to-month basis, which can be terminated by either party with 45-days' notice to the counterparty. We have also contracted for crude oil storage capacity for up to 90,000 barrels with a downstream interstate pipeline at a facility in DeWitt County, Texas, on a month-to-month basis which can be terminated by either party with 45-days' notice to the counterparty. Finally, we have an agreement with a marketing affiliate of the aforementioned downstream interstate pipeline to utilize up to 62,000 barrels of capacity within their system on a firm basis and an additional120,000 barrels, if available, on a flexible basis. Costs associated with these agreements are in the form of monthly fixed rate short-term leases and are charged as incurred on a monthly basis to GPT in our consolidated statements of operations.

Other Agreements

We have a long-term dedication of certain specific leases to a crude purchase and throughput terminal agreement into 2032. Under the agreement, we have rights to transfer dedicated oil for delivery to a gulf coast terminal in Point Comfort, Texas or oil may be transferred at alternate locations to third parties and pay the terminal fee.

We have agreements that provide us with field gathering, compression and short-haul transportation services for our natural gas production and gas lift for our hydrocarbon production under various terms through 2039.

We also have agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. Several agreements covering the majority of our wet gas production extend beyond three years, including one significant agreement that extends into 2029.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. As of December 31, 2021, we had an estimated reserve in the amount of $0.1 million for certain claims made against us regarding previously divested operations included in Accounts payable and accrued liabilities on our consolidated balance sheets.

Environmental Compliance

Extensive federal, state and local laws govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2021, we had AROs of $8.4 million and environmental remediation liabilities assumed in the Lonestar Acquisition of $2.3 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have purchase commitments for certain materials as well as minimum commitments under information technology licensing and service agreements, among others.

Note 15 – Shareholders' Equity

Capital Stock

Prior to the Lonestar Acquisition, the Company's authorized capital stock consisted of 115,000,000 shares including (i) 110,000,000 shares of common stock, par value $0.01 per share and (ii) 5,000,000 shares of Series A Preferred Stock, par value $0.01 per share.

On October 6, 2021, in connection with the consummation of the Lonestar Acquisition, the Company effected a recapitalization (the "Recapitalization"), pursuant to which (i) the Company's common stock was renamed and reclassified as Class A Common Stock, (ii) the authorized number of shares of capital stock of the Company was increased to 145,000,000 shares, (iii) 30,000,000 shares of Class B Common Stock, par value of $0.01 per share, a new class of capital stock of the Company, was authorized, (iv) all 225,489.98 outstanding shares of the Series A Preferred Stock were exchanged for 22,548,998 newly issued shares of Class B Common Stock, and (v) the designation of the Series A Preferred Stock was cancelled.

We have not paid any cash dividends on our common stock. In addition, our Credit Facility and the Indenture have restrictive covenants that limit our ability to pay dividends.

Paid-in Capital

Paid-in capital represents the value of consideration we received in excess of par value for the original issuance of our common stock net of costs directly attributable to the issuance transactions. In addition, paid-in capital includes amounts attributable to the amortized cost of share-based awards that have been granted to our employees and directors, net of any adjustments with the ultimate vesting of such awards.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income and losses are entirely attributable to our pension and postretirement health care benefit obligations. For further details on our pension and postretirement health care plans, see Note 16.

Note 16 – Share-Based Compensation and Other Benefit Plans

We reserved 4,424,600 shares of Class A Common Stock for issuance under the Ranger Oil Management Incentive Plan (the "Incentive Plan") for share-based compensation awards. A total of 762,259 time-vested restricted stock units ("RSUs") and484,197 performance-based restricted stock units ("PRSUs") have been granted to employees and directors through December 31, 2021.

The Merger Agreement provided the terms in which Lonestar share-based awards held by Lonestar employees were replaced with share-based awards of the Company ("replacement awards") on the acquisition date. For accounting purposes, the fair value of the replacement awards must be allocated between each employee's pre-combination and post-combination services. Amounts allocated to pre-combination services have been included as consideration transferred as part of the Lonestar Acquisition. See Note 4 for a summary of consideration transferred. Compensation costs of $10.4 million allocated to post-combination services were recorded as stock-based compensation expense from the immediate vesting of these awards pursuant to the terms of the Merger Agreement.

We recognized $15.6 million (including $10.4 million and $1.9 million as a result of the change-in-control events associated with the Lonestar Acquisition and the Juniper Transactions, respectively), $3.3 million and $4.1 million of share-based compensation expense for the years ended December 31, 2021, 2020 and 2019, respectively, and $0.5 million, $0.1 million and $0.1 million of related income tax benefits for the years ended December 31, 2021, 2020 and 2019, respectively. All of our share-based compensation awards are classified as equity instruments because they result in the issuance of common stock on the date of grant, upon exercise or are otherwise payable in common stock upon vesting, as applicable. The compensation cost attributable to these awards has been measured at the grant date and recognized over the applicable vesting periods as a non-cash expense.

Time-Vested Restricted Stock Units

The RSUs entitle the grantee to receive a share of common stock upon the achievement of the applicable service period vesting requirement. The grant date fair value of our time-vested RSU awards are recognized on a straight-line basis over the applicable vesting period, which is generally over a three-year period.

The following table summarizes activity for our most recent fiscal year with respect to awarded RSUs:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	319,280	$ 13.56
Granted	120,262	$ 14.12
Vested	(174,972)	$ 20.81
Forfeited	(34,053)	$ 10.65
Balance at end of year	230,517	$ 9.20

As of December 31, 2021, we had $1.5 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.85 years. The total grant date fair values of RSUs that vested in 2021, 2020 and 2019 were $3.6 million, $2.8 million and $3.0 million, respectively.

Performance Restricted Stock Units

The PRSUs entitle the grantee to receive a share of common stock upon the achievement of both service and market conditions.

The table below presents information pertaining to PRSUs granted in the following periods:

	2021	2020	2019
PRSUs granted [1]	225,206	145,399	15,066
Monte Carlo grant date fair value [2]	$17.74 to $33.31	$2.40 to $16.02	$ 34.02
Average grant date fair value [3]	$13.63	not applicable	not applicable

1 The 2020 PRSU grants include one executive officers' inducement award originally granted in August 2020 that was amended in April 2021 to conform vesting conditions to other PRSU awards granted in 2021.

2 Represents the Monte Carlo grant date fair value of 2021 and 2020 PRSU grants based on the Company's TSR performance (as defined below).

3 Represents the average grant date fair value of 2021 PRSU grants based on the Company's ROCE performance (as defined below).

Compensation expense for PRSUs with a market condition is being charged to expense on a straight-line basis for the 2021 grants and graded-vesting for the 2020 and 2019 grants, over a range of less than one to three years. Compensation expense for PRSUs with a performance condition is recognized on a straight-line basis over three years, when it is considered probable that the performance condition will be achieved and such grants are expected to vest.

The 2021 PRSU grants are based 50% on the Company's return on average capital employed ("ROCE") relative to a defined peer group and 50% based on the Company's absolute total shareholder return and total shareholder return ("TSR") relative to a defined peer group over the three year performance period. The 2021 PRSUs cliff vest from 0% to 200% of the original grant at the end of a three-year performance period based on satisfaction of the respective underlying conditions.

Vesting of PRSUs granted in 2020 and 2019 range from 0% to 200% of the original grant based on TSR relative to a defined peer group over thethree year performance period. As TSR is deemed a "market condition", the grant-date fair value for the 2019, 2020 and a portion of the 2021 PRSU grants is derived by using a Monte Carlo model. The ranges for the assumptions used in the Monte Carlo model for the PRSUs granted during 2021, 2020 and 2019 are presented as follows:

	2021 [1]	2020 [1]	2019
Expected volatility	131.74% to 134.74%	101.32% to 117.71%	49.90 %
Dividend yield	0.0 %	0.0 %	0.0 %
Risk-free interest rate	0.22% to 0.29%	0.18% to 0.51%	1.66 %
Performance period	2021-2023	2020-2022	2020-2022

1 One executive officer's inducement award originally granted in August 2020 was amended in April 2021 to conform vesting conditions to other PRSU awards granted in 2021. The Monte Carlo assumptions for both years are included above.

The following table summarizes activity for our most recent fiscal year with respect to PRSUs:

	Performance Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	173,532	$ 13.68
Granted	225,206	$ 22.44
Vested	(9,816)	$ 26.60
Forfeited	(43,853)	$ 14.90
Balance at end of year	345,069	$ 16.20

As of December 31, 2021, we had $5.0 million of unrecognized compensation cost attributable to PRSUs. We expect that cost to be recognized over a weighted-average period of 1.96 years.

Executive Transition and Retirement

In August 2020, we appointed Darrin Henke our new president and chief executive officer, or CEO, and director following the retirement of John Brooks. We incurred incremental G&A costs of approximately $1.2 million, in connection with Mr. Henke's appointment and Mr. Brooks' separation. In addition to those incremental costs, we recognized $0.7 million during the year ended December 31, 2020 for the accelerated vesting of certain share-based compensation awards of Mr. Brooks in connection with his retirement.

In December 2019, Steven A. Hartman separated from the Company. In accordance with his separation and transition agreement ("Hartman Separation Agreement"), we recorded a charge of $0.5 million for severance and other cash benefits that were paid in the first quarter of 2020. The Hartman Separation Agreement also provided for the accelerated vesting of certain share-based compensation awards for which we recognized accelerated expense of $0.2 million during the year ended December 31, 2019. The costs associated with the Hartman Separation Agreement, including the share-based compensation charges, were included as a component of General and administrative expenses in our consolidated statements of operations for the year ended December 31, 2019.

Defined Contribution Plan

We maintain the Penn Virginia Corporation and Affiliated Companies Employees 401(k) Plan (the "401(k) Plan"), a defined contribution plan, which covers substantially all of our employees. We provide matching contributions on our employees' elective deferral contributions up to 6% of compensation up to the maximum statutory limits. The 401(k) Plan also provides for discretionary employer contributions. The expense recognized with respect to the 401(k) Plan was $1.0 million, $0.9 million, $0.9 million for the years ended December 31, 2021, 2020 and 2019, respectively, and is included as a component of General and administrative expenses in our consolidated statements of operations. Amounts representing accrued obligations to the 401(k) Plan of $0.3 million and $0.2 million are included within Accounts payable and accrued expenses on our consolidated balance sheets as of December 31, 2021 and 2020, respectively.

Defined Benefit Pension and Postretirement Health Care Plans

We maintain unqualified legacy defined benefit pension and defined benefit postretirement health care plans which cover a limited population of former employees that retired prior to January 1, 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each year ended December 31, 2021, 2020 and 2019, and is included as a component of Other, net in our consolidated statements of operations. The combined unfunded benefit obligations under these plans were $1.1 million and $1.3 million as of December 31, 2021 and 2020, respectively, and are included within the Accounts payable and accrued liabilities (current portion) and Other liabilities (non-current portion) on our consolidated balance sheets.

Note 17 – Earnings Per Share

Basic net earnings (loss) per share is calculated by dividing the net income (loss) available to common shareholders, excluding net income or loss attributable to Noncontrolling interest, as applicable to the year ended December 31, 2021 (see Note 4), by the weighted average common shares outstanding for the period.

In computing diluted earnings (loss) per share, basic net earnings (loss) per share is adjusted based on the assumption that dilutive RSUs and PRSUs have vested and outstanding Common Units held by Juniper as a Noncontrolling interest in the Partnership are exchanged for common shares, as applicable to the year ended December 31, 2021 (see Note 4. Accordingly, our reported net income (loss) attributable to common shareholders is adjusted to reflect the reallocation of the net income (loss) attributable to the Noncontrolling interest assuming exchange of the Common Units held by Noncontrolling interest.

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Net income (loss)	$ 98,918	$ (310,557)	$ 70,589
Net income attributable to Noncontrolling interest	(58,689)	—	—
Net income (loss) attributable to common shareholders (basic)	40,229	(310,557)	70,589
Reallocation of Noncontrolling interest net income	58,689	—	—
Net income (loss) attributable to common shareholders (diluted)	$ 98,918	$ (310,557)	$ 70,589
Weighted-average shares – basic	16,695	15,176	15,110
Effect of dilutive securities:			
Common Units exchangeable for common shares	—	—	—
RSUs and PRSUs	470	—	16
Weighted-average shares – diluted [1]	17,165	15,176	15,126

[1] For the year ended December 31, 2021, approximately 22.5 million potentially dilutive Common Units, had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per share. For the year ended December 31, 2020, approximately 0.1 million potentially dilutive securities, represented by RSUs and PRSUs, respectively, had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per share.

Change in Ownership of Consolidated Subsidiaries

The following table summarizes changes in the ownership interest in consolidated subsidiaries during the period:

	Year Ended December 31,		
	2021	2020	2019
Net income (loss) attributable to common shareholders	$ 40,229	$ (310,557)	$ 70,589
Change in ownership of consolidated subsidiaries [1]	(57,604)	N/A	N/A
Change from net income (loss) attributable to common shareholders and transfers to Noncontrolling interest	$ (17,375)	$ (310,557)	$ 70,589

[1] The year ended December 31, 2021 includes an adjustment to Noncontrolling interest for the Lonestar Acquisition of $ 57.6 million and to Additional paid-in-capital of $ 57.6 million to reflect the change in ownership structure that was effective at October 5, 2021 relating to the noncontrolling interest arising from the Juniper Transactions on January 15, 2021. The adjustment had no impact on earnings. See Note 4 for further details.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserves

All of our proved oil and gas reserves are located in the continental United States. The estimates of our proved oil and gas reserves were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists. Our Senior Vice President and Chief Operating Officer is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc.

Reserve engineering is a process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future prices for these commodities may all differ from those assumed. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

The following table sets forth our estimate of net quantities of proved reserves, including changes therein and proved developed and proved undeveloped reserves for the periods presented:

Proved Developed and Undeveloped Reserves	**Oil (Mbbl)**	**NGLs (Mbbl)**	**Natural Gas (MMcf)**	**Total Equivalents (Mboe)**
December 31, 2018	89,656	18,044	91,493	122,950
Revisions of previous estimates	(24,709)	(4,055)	(25,440)	(33,006)
Extensions and discoveries	40,190	6,575	31,045	51,939
Production	(7,453)	(1,491)	(7,067)	(10,121)
Purchase of reserves	1,212	81	418	1,363
December 31, 2019	98,896	19,154	90,449	133,125
Revisions of previous estimates	(23,554)	(5,599)	(26,712)	(33,606)
Extensions and discoveries	29,966	3,208	15,357	35,734
Production	(6,829)	(1,165)	(5,360)	(8,887)
December 31, 2020	98,479	15,598	73,734	126,366
Revisions of previous estimates	(5,633)	(2,606)	(11,154)	(10,098)
Extensions and discoveries	45,709	9,877	47,774	63,548
Production	(7,711)	(1,326)	(6,712)	(10,155)
Purchase of reserves	32,278	18,476	121,550	71,012
December 31, 2021	163,122	40,019	225,192	240,673
Proved Developed Reserves:				
December 31, 2019	40,641	8,846	41,808	56,455
December 31, 2020	36,360	7,979	37,597	50,605
December 31, 2021	59,957	16,431	94,033	92,060
Proved Undeveloped Reserves:				
December 31, 2019	58,255	10,308	48,641	76,670
December 31, 2020	62,119	7,619	36,137	75,761
December 31, 2021	103,165	23,588	131,159	148,613

The following is a discussion and analysis of the significant changes in our proved reserve estimates for the periods presented:

Year Ended December 31, 2021

In 2021, our proved reserves increased by 114.3 MMboe due primarily to the Juniper transactions and the Lonestar Acquisition increasing our reserves. During the COVID-19 pandemic, Ranger Oil continued to drill and complete wells and increased drilling efficiencies in lateral footage capabilities. Additionally, we optimized and refreshed the existing drilling inventory to access stranded acreage and optimize for longer laterals, resulting in an increase in average treatable lateral per well, thus increasing the average reserves per well. This process resulted in an increase to extensions and discoveries of 63.5 MMboe that was offset by 14.0 MMboe of negative revisions due to schedule adjustment that moved wells beyond our five-year drilling window schedule. In addition, our revisions of previous estimates reflect: (i) 5.8 MMboe of favorable revisions attributable to changes in lateral lengths and type curves, offset by (ii) unfavorable revisions of 5.5 MMboe due to performance and (iii) favorable revisions due to pricing of 3.6 MMboe.

Year Ended December 31, 2020

In 2020, our proved reserves declined by 6.8 MMboe due primarily to lower commodity pricing reducing our reserves in excess of the positive revisions to replace production. In light of the ongoing COVID-19 pandemic and its impact on our capital resources, we undertook a substantial review of our drilling plans and available site inventory that resulted in a substantial shift in the focus of our near-term drilling schedule to a greater focus on our core, oilier prospects. This process resulted in an increase to extensions and discoveries of 35.7 MMboe that was largely offset by 34.0 MMboe of negative revisions due primarily to certain wells that are now beyond our five-year drilling window schedule. In addition, our revisions of previous estimates reflect: (i) 6.9 MMboe of favorable revisions attributable to changes in lateral lengths and type curves, substantially offset by (ii) unfavorable revisions of 3.2 MMboe due to performance and (iii) declines in pricing of 3.2 MMboe.

Year Ended December 31, 2019

In 2019, our proved reserves increased by 10.2 MMboe due primarily to substantial changes in our development plans from the southeast portion of our acreage position in the Eagle Ford to the central region. The overall shift to this region allows us to develop wells with a lower gas content than what we were experienced in the southeast region through the first half of 2019. After achieving more favorable results with certain wells in the central region, we proceeded to drill a total of 11 gross wells, or approximately 23% of our total wells drilled in 2019, in the central region that were not considered proved undeveloped locations at the end of 2018.

We had downward revisions of 33.0 MMboe including: (i) 32.1 MMboe due to a change in timing beyond five years attributable to our development plans as discussed above, as well as a reduction of drilling rigs from three to two, combining certain wells into extended reach lateral locations and other reductions due to changes in the plan of development, (ii) 2.7 MMboe due to 15% lower crude oil pricing from $65.56 per barrel to $55.67 per barrel and (iii) 1.6 MMboe due to reductions in lateral length and net revenue interests partially offset by (iv) 3.4 MMboe due to improved performance of certain proved undeveloped wells and proved undeveloped wells transferred to proved developed net of lower performance associated with certain existing proved developed wells including those reclassified to proved non-producing. Extensions and discoveries of 51.9 MMboe are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher estimated ultimate reserves (“EUR”) per lateral foot as well the addition of certain non-operated royalty wells. We acquired 1.4 MMboe in connection with the acquisition of certain non-operating partners working interests in locations in which we are the operator.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth capitalized costs related to our oil and gas producing activities and accumulated DD&A for the periods presented:

	December 31,		
	2021	2020	2019
Oil and gas properties:			
Proved	$ 2,327,686	$ 1,545,910	$ 1,409,219
Unproved	57,900	49,935	53,200
Total oil and gas properties	2,385,586	1,595,845	1,462,419
Other property and equipment	26,131	23,068	21,317
Total capitalized costs relating to oil and gas producing activities	2,411,717	1,618,913	1,483,736
Accumulated depreciation and depletion	(1,028,970)	(896,219)	(364,716)
Net capitalized costs relating to oil and gas producing activities [1]	$ 1,382,747	$ 722,694	$ 1,119,020

[1] Excludes property and equipment attributable to our corporate operations which is comprised of certain capitalized hardware, software, leasehold improvements and office furniture and fixtures.

Costs Incurred in Certain Oil and Gas Activities

The following table summarizes costs incurred in our oil and gas property acquisition, exploration and development activities for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Development costs	$ 262,439	$ 126,739	$ 335,925
Proved property acquisition costs [1]	—	—	6,051
Unproved property acquisition costs	3,687	3,448	7,570
Exploration costs	86	342	363
	$ 266,212	$ 130,529	$ 349,909

[1] Does not include the fair value of proved properties of $479.0 million recorded in the purchase price allocation with respect to the Lonestar Acquisition.The purchase was funded through the issuance of our common stock.

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

Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end, to the estimated future production of proved reserves. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected below do not necessarily represent the economic reality of such transactions.

Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per bbl and MMBtu with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price.

The following table summarizes the price measurements utilized, by product, with respect to our estimates of proved reserves as well as in the determination of the standardized measure of the discounted future net cash flows for the periods presented:

	Crude Oil	NGLs	Natural Gas
	$/bbl	$/bbl	$/MMBtu
December 31, 2019	$ 55.67	$ 13.36	$ 2.58
December 31, 2020	$ 39.54	$ 7.51	$ 1.99
December 31, 2021	$ 66.57	$ 22.99	$ 3.60

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	December 31,		
	2021	2020	2019
Future cash inflows	$ 12,157,254	$ 3,832,194	$ 6,260,292
Future production costs	(2,938,528)	(1,356,505)	(1,792,891)
Future development costs	(1,809,394)	(926,904)	(1,174,215)
Future net cash flows before income tax	7,409,332	1,548,785	3,293,186
Future income tax expense	(978,510)	(60,598)	(334,451)
Future net cash flows	6,430,822	1,488,187	2,958,735
10% annual discount for estimated timing of cash flows	(3,373,661)	(837,897)	(1,469,853)
Standardized measure of discounted future net cash flows	$ 3,057,161	$ 650,290	$ 1,488,882

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

The following table summarizes the changes in the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Sales of oil and gas, net of production costs	$ (476,734)	$ (194,660)	$ (374,694)
Net changes in prices and production costs	1,324,982	(950,201)	(402,616)
Changes in future development costs	(129,058)	450,286	415,193
Extensions and discoveries	753,601	74,830	459,501
Development costs incurred during the period	131,743	102,459	253,982
Revisions of previous quantity estimates	(188,804)	(303,219)	(515,345)
Purchases of reserves-in-place	926,169	—	12,241
Changes in production rates and all other	353,520	(282,055)	(194,453)
Accretion of discount	65,755	160,010	176,935
Net change in income taxes	(354,303)	103,958	34,248
Net increase (decrease)	2,406,871	(838,592)	(135,008)
Beginning of year	650,290	1,488,882	1,623,890
End of year	$ 3,057,161	$ 650,290	$ 1,488,882

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

(a) Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2021. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to the issuer's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2021, such disclosure controls and procedures were effective.

In conducting management's evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2021, we have excluded Lonestar as permitted by SEC Staff guidance because it was acquired by the Company in a purchase business combination during 2021. The total revenues and total assets of legacy Lonestar subsidiaries represent approximately 11% and 33%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2021.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2021. This evaluation was completed based on the framework established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on that assessment, our management has concluded that, as of December 31, 2021, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

Grant Thornton LLP, the independent registered public accounting firm that audited and reported on the consolidated financial statements contained in this Form 10-K, has issued an attestation report on the internal control over financial reporting as of December 31, 2021, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

Except for certain incremental changes relating to the integration of Lonestar, no changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Management continues to integrate Lonestar's internal control over financial reporting with the Company's internal control over financial reporting. This integration may lead to changes in these controls in future fiscal periods but management does not yet know whether these changes will materially affect our internal control over financial reporting. Management expects the integration process to be completed during 2022.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

We have adopted a Code of Business Conduct and Ethics that applies to all of our directors, officer and employees, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Business Conduct and Ethics is posted on our website located at https://ir.rangeroil.com/governance-docs. We intend to disclose future amendments to certain provisions of the Code of Business Conduct and Ethics, and any waivers of the Code of Business Conduct and Ethics granted to executive officers and directors, on the website within four business days following the date of the amendment or waiver.

Item 11. Executive Compensation

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accountant Fees and Services

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page64 of this Annual Report on Form 10-K.

(2) Exhibits

The following documents are included as exhibits to this Annual Report on Form 10-K. Those exhibits incorporated by reference are indicated as such in the parenthetical following the description. All other exhibits are included herewith.

Exhibit Number	Description
(2.1)	Contribution Agreement, dated as of November 2, 2020, by and among Penn Virginia Corporation, PV Energy Holdings, L.P. and JSTX Holdings, LLC (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on November 5, 2020).
(2.2)	Contribution Agreement, dated as of November 2, 2020, by and among Penn Virginia Corporation, PV Energy Holdings, L.P. and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on November 5, 2020).
(2.3)	Merger Agreement, dated as of July 10, 2021, by and among Penn Virginia, Merger Sub Inc, Merger Sub LLC and Lonestar (incorporated by reference to Exhibit 2.1 to Registrants Current Report on Form 8-K filed on July 13, 2021).
(3.1)	Fourth Amended and Restated Articles of Incorporation of Ranger Oil Corporation, effective as of October 6, 2021 (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on October 7, 2021).
(3.2)	Articles of Amendment, dated as of October 14, 2021, to the Fourth Amended and Restated Articles of Incorporation of Ranger Oil Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on October 19, 2021).
(3.3)	Seventh Amended and Restated Bylaws of Ranger Oil Corporation, effective as of October 6, 2021 (incorporated by reference to Exhibit 3.3 to Registrant's Current Report on Form 8-K filed on October 7, 2021).
(3.4)	Amendment to the Seventh Amended and Restated Bylaws of Ranger Oil Corporation, effective October 14, 2021 (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on October 19, 2021).
(4.1.1)	Indenture, dated as of August 10, 2021 among Penn Virginia Escrow LLC, the guarantors party thereto and Citibank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on August 13, 2021).
(4.1.2)	Supplemental Indenture – Escrow Merger, dated as of October 5, 2021, by and among Penn Virginia Holdings, LLC, each of the parties identified therein as Guarantors and Citibank, N.A. (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 13, 2021).
(4.1.3)	Supplemental Indenture – Subsidiary Guarantee, dated as of October 6, 2021, by and among Penn Virginia Holdings, LLC, each of the parties identified therein as Subsequent Guarantors and Citibank, N.A. (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on October 13, 2021).
(4.2)	Form of 9.250% Senior Note due 2026 (incorporated by reference as Exhibit A to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on August 13, 2021).
(4.3)#	Description of Common Stock.
(10.1)	Pledge and Security Agreement, dated as of September 12, 2016, by Penn Virginia Holding Corp., Penn Virginia Corporation and the other grantors party thereto in favor of Wells Fargo Bank, National Association, as administrative agent for the benefit of the secured parties thereunder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(10.2)	Registration Rights Agreement, dated as of September 12, 2016 between Penn Virginia Corporation and the holders party thereto (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(10.3)	Contribution and Exchange Agreement, dated as of October 6, 2021, by and between Penn Virginia Corporation, JSTX Holdings, LLC and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 7, 2021).
(10.4)	Second Amended and Restated Construction and Field Gathering Agreement by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. dated August 1, 2016 (incorporated by reference to Exhibit 10.5 to Registrant's Quarterly Report on Form 10-Q/A filed on November 28, 2016).
(10.5.1)	Amendment No. 1 to the Second Amended and Restated Construction and Field Gathering Agreement dated as of April 13, 2017 but effective August 1, 2016 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. (incorporated by reference to Exhibit 10.4.1 to Registrant 's Registration Statement on Form S-3/A (Amendment No. 2) filed on May 2, 2017).
(10.5.2)	Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of July 2, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.5.3)	Third Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of December 14, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.9.3 to Registrant 's Annual Report on Form 10-K filed on February 27, 2019).

(10.6.1)	First Amended and Restated Crude Oil Marketing Agreement dated as of August 1, 2016, by and between Penn Virginia Oil & Gas, L.P., Republic Midstream Marketing, LLC and solely for purposes of Article V therein, Penn Virginia Corporation (incorporated by reference to Exhibit 10.6 to Registrant's Quarterly Report on Form 10-Q/A filed on November 28, 2016).
(10.6.2)†	First Amendment to First Amended and Restated Crude Oil Marketing Agreement dated as of July 2, 2018 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream Marketing, LLC.(incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.7)*	Penn Virginia Corporation 2019 Management Incentive Plan (incorporated by reference to Appendix A to Company 's Definitive Proxy Statement for its 2019 Annual General Meeting of Shareholders filed on July 1, 2019).
(10.7.1)*	Form of Officer Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.11.2 to Registrant's Annual Report on Form 10-K filed on February 28, 2020).
(10.7.2)*	Form of Performance Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.11.3 to Registrant's Annual Report on Form 10-K filed on February 28, 2020).
(10.7.3)*	Form of Director Restricted Stock Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on September 6, 2019).
(10.7.4)*	Penn Virginia Corporation 2017 Special Severance Plan Amended and Restated Effective August 17, 2020 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on August 21, 2020).
(10.7.5)*	Form of Performance Restricted Stock Unit Award Agreement (Officer) (incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2021).
(10.7.6)*	Amendment No. 1 to the Penn Virginia Corporation 2017 Special Severance Plan (incorporated by reference to Exhibit 10.14 to Registrant's Current Report on Form 10-K filed on March 9, 2021).
(10.8)	Form of Director Indemnification Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 11, 2016).
(10.9)*	Form of Officer Indemnification Agreement (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on August 21, 2020).
(10.10)	Master Assignment, Agreement and Amendment No. 11 to the Credit Agreement, entered into and dated as of August 18, 2021, among Penn Virginia Holdings, LLC, as borrower, Penn Virginia Corporation, as holdings, certain subsidiaries of holdings party thereto, certain lenders party thereto, Wells Fargo Bank National Association, as administrative agent for the lenders an as an issuing lender, Citibank, N.A., as the issuer of certain letters of credit and such other persons identified as a "New Lender" on the signature pages thereto (incorporated by references to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on August 24, 2021).
(10.11)	Second Amended and Restated Agreement of Limited Partnership, dated as of October 6, 2021, by and among PV Energy Holdings GP, LLC, Penn Virginia Corporation, JSTX Holdings, LLC and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 7, 2021).
(10.12)	Amended and Restated Investor and Registration Rights Agreement, dated October 6, 2021, by and among Penn Virginia Corporation, JSTX Holdings, LLC and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 7, 2021).
(21.1)#	Subsidiaries of Ranger Oil Corporation.
(23.1)#	Consent of Grant Thornton LLP.
(23.2)#	Consent of DeGolyer and MacNaughton.
(31.1)#	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)#	Certification Pursuant to 18 Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)††	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)††	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1)#	Report of DeGolyer and MacNaughton dated February 7, 2022 concerning evaluation of oil and gas reserves.
(101.INS)#	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
(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)#	The cover page of Ranger Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2021, formatted in Inline XBRL (included within the Exhibit 101 attachments).

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* Management contract or compensatory plan or arrangement.

\# Filed herewith.

† Confidential treatment has been requested for this exhibit and confidential portions have been filed separately with the Securities and Exchange Commission.

†† Furnished herewith.

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.

RANGER OIL CORPORATION

March 8, 2022	By:	/s/ RUSSELL T KELLEY, JR.
		Russell T Kelley, Jr. **Senior Vice President, Chief Financial Officer and Treasurer** **(Principal Financial Officer)**
March 8, 2022	By:	/s/ KAYLA D. BAIRD
		Kayla D. Baird **Vice President, Chief Accounting Officer and Controller** **(Principal Accounting Officer)**

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

/s/ DARRIN J. HENKE **Darrin J. Henke**	President and Chief Executive Officer and Director (Principal Executive Officer)	March 8, 2022
/s/ RUSSELL T KELLEY, JR. **Russell T Kelley, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	March 8, 2022
/s/ KAYLA D. BAIRD **Kayla D. Baird**	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	March 8, 2022
/s/ RICHARD BURNETT **Richard Burnett**	Director	March 8, 2022
/s/ TIFFANY THOM CEPAK **Tiffany Thom Cepak**	Director	March 8, 2022
/s/ KEVIN CUMMING **Kevin Cumming**	Director	March 8, 2022
/s/ EDWARD GEISER **Edward Geiser**	Chairman of the Board	March 8, 2022
/s/ TIMOTHY W. GRAY **Timothy W. Gray**	Director	March 8, 2022
/s/ TEMITOPE OGUNYOMI **Temitope Ogunyomi**	Director	March 8, 2022
/s/ JOSHUA SCHMIDT **Joshua Schmidt**	Director	March 8, 2022
/s/ JEFFREY WOJAHN **Jeffrey Wojahn**	Director	March 8, 2022

Exhibit 4.3

DESCRIPTION OF CAPITAL STOCK

The following summary of certain provisions of the capital stock of Ranger Oil Corporation ("we," "our," "us" and "our company") does not purport to be complete and is subject to and is qualified in its entirety by our Fourth Amended and Restated Articles of Incorporation (as amended, the "Articles of Incorporation") and our Seventh Amended and Restated Bylaws (as amended, the "Bylaws"). We urge you to read the Articles of Incorporation, the Bylaws and the applicable provisions of the Virginia Stock Corporation Act ("VSCA"). The Articles of Incorporation and Bylaws are incorporated by reference as exhibits to the Annual Report on Form 10-K, of which this Exhibit 4.1 is a part.

As of March 4, 2022, our authorized capital stock was 145,000,000 shares. Those shares consisted of (i) 110,000,000 shares of Class A common stock, par value $0.01 per share ("Class A common stock"), of which 21,115,294 were outstanding as of March 4, 2022, (ii) 30,000,000 authorized shares of Class B common stock, par value $0.01 per share ("Class B common stock"), of which 22,548,998 shares were outstanding as of March 4, 2022, and (iii) 5,000,000 shares of preferred stock, par value $0.01 per share, of which no shares were outstanding as of March 4, 2022.

Our Class A common stock is currently listed on the Nasdaq Global Select Market under the symbol "ROCC."

Common Stock

We have two classes of common stock: Class A common stock and Class B common stock. Except as otherwise required by law or the Articles of Incorporation, each holder of Class A common stock and Class B common stock is entitled to one vote for each share of common stock held of record by such holder. The holders of record of Class A common stock and Class B common stock vote together as a single class on all matters on which holders of the Class A common stock and Class B common stock are entitled to vote (and, if any holders of preferred stock are entitled to vote together with the holders of Class A common stock and Class B common stock, as a single class with such holders of preferred stock); provided, however, that the directors designated by JSTX Holdings, LLC ("JSTX") and Rocky Creek Resources, LLC ("Rocky Creek", and together with JSTX and each of their respective successors and permitted assigns, collectively, the "Permitted Class B Owners") will be elected by holders of a majority of the shares of Class B common stock voting as a separate class. See "—Class B Common Stock—Board Representation" below.

Holders of Class A common stock and Class B common stock may not cumulate their votes in the elections of directors. Except as otherwise required by the Articles of Incorporation or the VSCA, the vote required to constitute any voting group's approval of a plan of merger or share exchange is a majority of all the votes cast thereon by such voting group. Except as otherwise required by the Articles of Incorporation, or described herein, the affirmative vote of more than two-thirds of the outstanding shares of our Class A common stock and Class B common stock is required for amendments to the Articles of Incorporation, the approval of certain sales or other dispositions of assets outside the usual and regular course of business, conversions, domestications and dissolutions. The affirmative vote of at least 67% of the total voting power of all of our outstanding shares entitled to vote generally in the election of directors, voting together as a single class, is required to amend the "Corporate Opportunity" provisions of the Articles of Incorporation described below. Except as otherwise required by the Articles of Incorporation, or described herein, all other matters to be voted on by shareholders must be approved by a majority of the votes cast on the matter.

Class A common stock

On October 6, 2021, all outstanding shares of our common stock were renamed and reclassified as shares of Class A common stock. The holders of shares of Class A common stock are not entitled to vote on any amendment to the Articles of Incorporation that relates solely to the terms of one or more outstanding series of preferred stock or other class of common stock (including the Class B common stock) if the holders of such affected series or class, as the case may be, are entitled, either separately or together with the holders of one or more other such series or class, to vote thereon pursuant to the Articles of Incorporation or pursuant to the VSCA, provided that such amendment does not alter or change the designations, powers, preferences or rights of the shares of Class A common stock so as to affect them adversely.

The holders of Class A common stock have no preemptive rights to purchase shares of Class A common stock. Shares of Class A common stock are not subject to any redemption or sinking fund provisions and are not convertible into any of our other securities. In the event of our voluntary or involuntary liquidation, dissolution or winding up, holders of Class A common stock will share equally in the assets remaining after it pays its creditors and preferred shareholders. Holders of our Class A common stock are entitled to receive dividends when and if declared by our Board of Directors out of funds legally available therefor, subject to any statutory or contractual restrictions on the payment of dividends and to any restrictions on the payment of dividends imposed by the terms of any outstanding preferred stock. All outstanding shares of Class A common stock are fully paid and non-assessable.

Class B Common Stock

On October 6, 2021, all outstanding shares of our Series A Preferred Stock were exchanged for shares of the newly authorized Class B common stock at a ratio of one share of Class B common stock for each 1/100th of a share of Series A Preferred Stock.

Shares of our Class B common stock are non-economic interests in our company, and no dividends can be declared or paid on the Class B common stock. In the event of our voluntary or involuntary liquidation, dissolution or winding up, after payment or provision for payment of our debts and other liabilities, the holders of the Class B common stock will be entitled to receive, out of our assets or proceeds thereof available for distribution to our shareholders, before any distribution of such assets or proceeds is made to or set aside for the holders of Class A common stock and any other of our stock ranking junior to the Class B common stock as to such distribution, payment in full in an amount equal to $0.0001 per share of Class B common stock. With exception of the aforementioned distribution, the holders of shares of Class B common stock will not be entitled to receive any of our assets in the event of our voluntary or involuntary liquidation, dissolution or winding up.

Our Class B common stock is not convertible into any of our other securities. However, if a holder exchanges one common unit of PV Energy Holdings, L.P., a Delaware limited partnership (the “Partnership”), for one share of our Class A common stock, it must also surrender to us a share of our Class B common stock for each common unit exchanged.

For so long as any shares of Class B common stock remain outstanding, we may not, without the prior vote or written consent of the holders of a majority of the shares of Class B common stock then outstanding, voting separately as a single class, amend, alter or repeal any provision of the Articles of Incorporation, whether by merger, consolidation or otherwise, if such amendment, alteration or repeal would adversely alter or change the powers, preferences or relative, participating, optional or other or special rights of the Class B common stock.

The holders of Class B common stock have no preemptive rights to purchase shares of Class B common stock. Shares of Class B common stock are not subject to any redemption or sinking fund provisions. All outstanding shares of Class B common stock are fully paid and non-assessable.

Board Representation

As of October 6, 2021, our Board of Directors was composed of nine members. For so long as the Permitted Class B Owners have the right to redeem or exchange common units for Class A common stock pursuant to the partnership agreement of the Partnership, holders of a majority of the total number of outstanding shares of Class B common stock are entitled to designate to our Board of Directors the following number of directors:

- up to five directors until such time as the number of shares of Class A common stock and Class B common stock then held by the Permitted Class B Owners (such sum, the “Total Class B Ownership”) is less than or equal to 50% of the number of shares of Class A common stock and Class B common stock combined then outstanding (such sum, the “Total Shares”);
- up to four directors until such time as the Total Class B Ownership continuously held is less than 40% of the Total Shares;
- up to three directors until such time as the Total Class B Ownership continuously held is less than 30% of the Total Shares;
- up to two directors until such time as the Total Class B Ownership continuously held is less than 20% of the Total Shares; and
- one director until such time as the Total Class B Ownership continuously held is less than 10% of the Total Shares.

For so long as the Permitted Class B Owners have the right to designate any directors, the size of our Board of Directors will not be decreased in a manner that would limit the above listed designation rights. Upon the occurrence of the above step-downs, such directors designated by the Permitted Class B Owners in excess of the entitled number of designations will promptly resign from our Board of Directors, the size of our Board of Directors will automatically be reduced as applicable and any right to designate such directors will automatically terminate.

Preferred Stock

Our Board of Directors is authorized, without approval of shareholders, to issue one or more series of preferred stock. Subject to the provisions of the Articles of Incorporation and limitations prescribed by law, our Board of Directors may adopt an amendment to the Articles of Incorporation setting the number of shares of each series and the rights, preferences and limitations of each series, including the dividend rights, voting rights, conversion rights, redemption rights and any liquidation preferences of any wholly unissued series of preferred stock, the number of shares constituting each series and the terms and conditions of issue.

Undesignated preferred stock may enable our Board of Directors to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of the holders of our Class A common stock and Class B common stock. For example, any preferred stock issued may rank prior to our Class A common stock and Class B common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of Class A common stock. As a result, the issuance of shares of preferred stock may discourage bids for our Class A common stock or may otherwise adversely affect the market price of our Class A common stock or any then existing preferred stock.

Anti-Takeover Provisions

Certain provisions in the Articles of Incorporation and the Bylaws, as well as certain provisions of Virginia law, may make more difficult or discourage a takeover of our business.

Certain Provisions of the Articles of Incorporation and the Bylaws

Shareholder Action by Unanimous Consent. Any action that could be taken by shareholders at a meeting may be taken, instead, without a meeting and without notice if a consent in writing is signed by all the shareholders entitled to vote on the action.
Blank Check Preferred Stock. The Articles of Incorporation authorize the issuance of blank check preferred stock. As described above under "—Preferred Stock," our Board of Directors can set the voting rights, redemption rights, conversion rights and other rights relating to such preferred stock and could issue such stock in either private or public transactions. In some circumstances, the blank check preferred stock could be issued and have the effect of preventing a merger, tender offer or other takeover attempt that the Board opposes.

Vacancies in the Board. Subject to the rights of any preferred stock and the rights of the Permitted Class B Owners described above, any vacancy in our Board of Directors resulting from any death, resignation, retirement, disqualification, removal from office or newly created directorship resulting from an increase in the authorized number of directors or otherwise may be filled by majority vote of the remaining directors then in office, even if less than a quorum, or shareholders.

Special Meetings of Shareholders. Special meetings of shareholders may be called at any time and from time to time only upon the written request of our Board of Directors, the chairman of our Board of Directors or the holders of a majority of the total voting power of all of our outstanding shares entitled to vote generally in the election of directors.

Advance Notice Requirements for Shareholder Director Nominations and Shareholder Business The Bylaws require that advance notice of shareholder director nominations and shareholder business for annual meetings be made in writing and given to our corporate secretary, together with certain specified information, not less than 90 days nor more than 120 days before the anniversary of the immediately preceding annual meeting of shareholders, subject to other timing requirements as specified in the Bylaws.

Virginia Anti-Takeover Statutes and Other Virginia Laws

Control Share Acquisitions Statute. Under the Virginia control share acquisitions statute, shares acquired in an acquisition that would cause an acquiror's voting strength to meet or exceed any of three thresholds (20%, 33 1/3% or 50%) have no voting rights unless (1) those rights are granted by a majority vote of all outstanding shares other than those held by the acquiror or any officer or employee director of the corporation or (2) the articles of incorporation or bylaws of the corporation provide that the provisions of the control share acquisitions statute do not apply to acquisitions of its shares. An acquiring person that owns five percent or more of the corporation's voting stock may require that a special meeting of the shareholders be held to consider the grant of voting rights to the shares acquired in the control share acquisition. This regulation was designed to deter certain takeovers of Virginia public corporations. Virginia law permits corporations to opt out of the control share acquisition statute. We have not opted out.

Affiliated Transactions. Under the Virginia anti-takeover law regulating affiliated transactions, material acquisition transactions between a Virginia corporation and any holder of more than 10% of any class of its outstanding voting shares are required to be approved by the holders of at least two-thirds of the remaining voting shares. Affiliated transactions subject to this approval requirement include mergers, share exchanges, material dispositions of corporate assets not in the ordinary course of business, any dissolution of the corporation proposed by or on behalf of a 10% holder or any reclassification, including reverse stock splits, recapitalization or merger of the corporation with its subsidiaries, that increases the percentage of voting shares owned beneficially by a 10% holder by more than five percent. For three years following the time that a shareholder becomes an interested shareholder, a Virginia corporation cannot engage in an affiliated transaction with the interested shareholder without approval of two-thirds of the disinterested voting shares and a majority of the disinterested directors. A disinterested director is a director who was a director on the date on which an interested shareholder became an interested shareholder or was recommended for election or elected by a majority of the disinterested directors then on the board. After three years, the approval of the disinterested directors is no longer required. The provisions of this statute do not apply if a majority of disinterested directors approve the acquisition of shares making a person an interested shareholder. As permitted by Virginia law, we have opted out of the affiliated transactions provisions.

Director Standards of Conduct. Under Virginia law, directors must discharge their duties in accordance with their good faith business judgment of the best interests of the corporation. Directors may rely on the advice or acts of others, including officers, employees, attorneys, accountants and board committees if they have a good faith belief in their competence. Virginia law provides that, in determining the best interests of the corporation, a director may consider the possibility that those interests may best be served by the continued independence of the corporation.

Exhibit 21.1

Subsidiaries of Ranger Oil Corporation

Name	Jurisdiction of Organization
Albany Services, L.L.C.	Texas
Boland Building, LLC	Texas
Eagleford Gas, LLC	Texas
Eagleford Gas 2, LLC	Texas
Eagleford Gas 3, LLC	Texas
Eagleford Gas 4, LLC	Texas
Eagleford Gas 5, LLC	Texas
Eagleford Gas 6, LLC	Texas
Eagleford Gas 7, LLC	Texas
Eagleford Gas 8, LLC	Texas
Eagleford Gas 10, LLC	Texas
Eagleford Gas 11, LLC	Texas
La Salle Eagle Ford Gathering Line LLC	Texas
Lonestar BR Disposal LLC	Texas
Lonestar Operating, LLC	Texas
Lonestar Resources America LLC	Delaware
Lonestar Resources, LLC	Delaware
Penn Virginia Holdings, LLC	Delaware
Penn Virginia Oil & Gas, LLC	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC, LLC	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings, LLC	Delaware
Pi Merger Sub LLC	Delaware
Poplar Energy, LLC	Texas
PV Energy Holdings GP, LLC	Delaware
PV Energy Holdings, L.P.	Delaware
T-N-T Engineering, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 8, 2022, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Ranger Oil Corporation on Form 10-K for the year ended December 31, 2021. We consent to the incorporation by reference of said reports in the Registration Statements of Ranger Oil Corporation on Form S-4 (File No. 333-259017), Forms S-3 (File No. 333-254050, File No. 333-238137, and File No. 333-214709) and Forms S-8 (File No. 333-258443, File No. 333-252026, File No. 333-248403, File No. 333-213979, and File No. 333-233364).

/s/ GRANT THORNTON LLP

Houston, Texas
March 8, 2022

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 8, 2022

Ranger Oil Corporation
16285 Park Ten Place, Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our report entitled "Report as of December 31, 2021 on Reserves and Revenue of Certain Properties with interests attributable to Ranger Oil Corporation" (our Report) in Part I and in the "Notes to Consolidated Financial Statements" portion of the Annual Report on Form 10-K of Ranger Oil Corporation for the year ended December 31, 2021 (the Annual Report), to be filed with the United States Securities and Exchange Commission on or about March 8, 2022.

We further consent to the incorporation by reference of our report of third party dated February 7, 2022, in the "Exhibits and Financial Statement Schedules" portion of the Annual Report. We further consent to the incorporation by reference of references to DeGolyer and MacNaughton and to our Report in Ranger Oil Corporation's Registration Statements on Form S-4 (File No. 333-259017), Form S-3 (File Nos. 333-254050, 333-238137, and 333-214709), and Form S-8 (File Nos. 333-258443, 333-252026, 333-248403, 333-213979, and 333-233364).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Darrin J. Henke, President and Chief Executive Officer of Ranger Oil Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

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

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

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

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

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

   (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 quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

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

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

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

Date: March 8, 2022

/s/ DARRIN J. HENKE

Darrin J. Henke
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer of Ranger Oil Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

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

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

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

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

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

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

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

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

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

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

Date: March 8, 2022

/s/ RUSSELL T KELLEY, JR

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

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

In connection with the Annual Report of Ranger Oil Corporation (the "Company") on Form 10-K for the year ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Darrin J. Henke, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: March 8, 2022

/s/ DARRIN J. HENKE

Darrin J. Henke
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Annual Report of Ranger Oil Corporation (the "Company") on Form 10-K for the year ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: March 8, 2022

/s/ RUSSELL T KELLEY, JR.

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road Suite 800 East
Dallas, Texas 75244
February 7, 2022

Ranger Oil Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2021, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Ranger Oil Corporation (Ranger) has represented it holds an interest. This evaluation was completed on February 7, 2022. The properties evaluated herein consist of working and royalty interests located in Texas. Ranger has represented that these properties account for 100 percent on a net equivalent barrel basis of Ranger's net proved reserves as of December 31, 2021. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Ranger.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Ranger after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Ranger to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Ranger, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Ranger and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Ranger with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* - Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> > (i) The area of the reservoir considered as proved includes:
> > (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
> >
> > (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
> >
> > (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
> > (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
> > (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
> >
> > (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Ranger, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Ranger.

Ranger has represented that its senior management is committed to the development plan provided by Ranger and that Ranger has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Ranger from wells drilled through December 31, 2021, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through October 2021. Estimated cumulative production, as of December 31, 2021, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 2 months.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C5+) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Ranger, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Ranger. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Ranger has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Ranger supplied differentials to a West Texas Intermediate (WTI) reference price of $66.57 per barrel and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $63.95 per barrel of oil and condensate and $22.99 per barrel of NGL.

Gas Prices

Ranger has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Ranger supplied differentials to a Henry Hub reference price of $3.598 per million Btu and the prices were held constant thereafter. Btu factors provided by Ranger were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $3.574 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for Texas. Ad valorem taxes were calculated using rates provided by Ranger based on recent payments

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Ranger and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2021 values, provided by Ranger, and were not adjusted for inflation. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Ranger and were not adjusted for inflation. At the request of Ranger, abandonment costs and any associated negative future net revenue have been included herein for those proved developed properties for which reserves were estimated to be zero. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2020, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized in the following table, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2021			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	59,957	16,431	94,033	92,060
Proved Undeveloped	103,165	23,588	131,159	148,613
Total Proved	**163,122**	**40,019**	**225,192**	**240,673**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2021, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	**Total Proved (M$)**
Future Gross Revenue	4,552,298	12,157,254
Production and Ad Valorem Taxes	295,040	782,474
Operating Expenses	1,061,897	2,156,054
Capital and Abandonment Costs	46,208	1,809,394
Future Net Revenue	3,149,153	7,409,332
Present Worth at 10 Percent	1,772,416	3,418,720

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2021, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Ranger. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Ranger. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

/s/ Dilhan Ilk, P.E.

Dilhan Ilk, P.E.

Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Ranger dated February 7, 2022, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 11 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk,, P.E.

Dilhan Ilk, P.E.

Senior Vice President
DeGolyer and MacNaughton