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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2021
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-35380

Laredo Petroleum, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

15 W. Sixth Street	**Suite 900**	
Tulsa	**Oklahoma**	**74119**
(Address of principal executive offices)		(Zip code)

(918) 513-4570

(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading symbol	Name of each exchange on which registered
Common stock, $0.01 par value per share	LPI	New York Stock Exchange

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. (Check one):

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.2 billion on June 30, 2021, based on $92.79 per share, the last reported sales price of the common stock on the New York Stock Exchange on such date.

Number of shares of registrant's common stock outstanding as of February 22, 2022: 17,304,100

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2022 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2021, are incorporated by reference into Part III of this report for the year ended December 31, 2021.

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Glossary of Oil and Natural Gas Terms

The following terms are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"*2D*"—Method for collecting, processing and interpreting seismic data in two dimensions.

"*3D*"—Method for collecting, processing and interpreting seismic data in three dimensions.

"*Allocation well*"—A horizontal well drilled by an oil and gas producer under two or more leaseholds that are not pooled, under a permit issued by the RRC.

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

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

"*Benchmark Prices*"—The unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials, as required by SEC guidelines.

"*BOE*"—One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"*BOE/D*"—BOE per day.

"Brent"—A light (low density) and sweet (low sulfur) crude oil sourced from the North Sea, used as a pricing benchmark for ICE oil futures contracts.

"*Btu*"—British thermal unit, the quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

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

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

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

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

"*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 natural gas in another reservoir.

"*Field*"—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

"*Fracturing*" or "*Frac*"—The propagation of fractures in a rock layer by a pressurized fluid. This technique is used to release petroleum and natural gas for extraction.

"*GAAP*"—Generally accepted accounting principles in the United States.

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

"*HBP*"—Acreage that is held by production.

"Henry Hub"—A natural gas pipeline delivery point in south Louisiana that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.

"*Horizon*"—A term used to denote a surface in or of rock, or a distinctive layer of rock that might be represented by a reflection in seismic data.

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

"ICE"—The Intercontinental Exchange.

"*Initial Production*"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.

"*Liquids*"—Describes oil, condensate and natural gas liquids.

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

"*MBOE*"—One thousand BOE.

"*MMBOE*"—One million BOE.

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

"*MMBtu*"—One million Btu.

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

"*Natural gas liquids*" or "*NGL*"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.

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

"*Net revenue interest*"—An owner's interest in the revenues of a well after deduction proceeds allocated to royalty and overriding interests.

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

"*Overriding royalty interest*"—A fractional undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

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

"*Proved developed non-producing reserves*" or "*PDNP*"—Developed non-producing reserves.

"*Proved developed reserves*" or "*PDP*"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*"—The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"*Proved undeveloped reserves*" or "*PUD*"—Proved reserves that are expected to be recovered within five years from new wells on undrilled locations and for which a specific capital commitment has been made or from existing wells where a relatively major expenditure is required for recompletion.

"*Realized Prices*"—Prices which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point without giving effect to our commodity derivative transactions.

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

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

"*Royalty interest*"—An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any development costs, which may be subject to expiration.

"*RRC*"—The Railroad Commission of Texas.

"*Spacing*"—The distance between wells producing from the same reservoir.

"*Standardized measure*"—Discounted future net cash flows estimated by applying Realized Prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Three stream*"—Production or reserve volumes of oil, natural gas liquids and natural gas, where the natural gas liquids have been removed from the natural gas stream and the economic value of the natural gas liquids is separated from the wellhead natural gas price.

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

"*Wellhead natural gas*"—Natural gas produced at or near the well.

"*Wolfberry Play*"—A general industry term that applies to the vertical stratigraphic interval that can include both the shallow Spraberry formation and the deeper Wolfcamp formation throughout the Permian Basin.

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

"*WTI*"—West Texas Intermediate grade crude oil. A light (low density) and sweet (low sulfur) crude oil, used as a pricing benchmark for NYMEX oil futures contracts.

Cautionary Statement Regarding Forward-Looking Statements

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil, NGL and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the effects, duration, government response or other implications of the coronavirus ("COVID-19"), or the threat and occurrence of other epidemic or pandemic diseases;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas, including as a result of the COVID-19 pandemic and actions by the Organization of the Petroleum Exporting Countries members and other oil exporting nations ("OPEC+");
- the volatility of oil, NGL and natural gas prices, including in our area of operation in the Permian Basin;
- the potential impact of suspending drilling programs and completions activities or shutting in a portion of our wells, as well as costs to later restart, and co-development considerations such as horizontal spacing, vertical spacing and parent-child interactions on production of oil, NGL and natural gas from our wells;
- United States ("U.S.") and international economic conditions and legal, tax, political and administrative developments, including the effects of energy, trade and environmental policies and existing and future laws and government regulations;
- possible war and political instability in Ukraine and possible Russian efforts to destabilize the government of Ukraine and the global hydrocarbon market;
- our ability to comply with federal, state and local regulatory requirements;
- the ongoing instability and uncertainty in the U.S. and international energy, financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- our ability to execute our strategies, including our ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses, assets and properties; our ability to realize the anticipated benefits of the Sabalo/Shad Acquisition and the Pioneer Acquisition (as defined below), including effectively managing our expanded acreage;
- competition in the oil and natural gas industry;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves and inventory;
- drilling and operating risks, including risks related to hydraulic fracturing activities and those related to inclement or extreme weather, impacting our ability to produce existing wells and/or drill and complete new wells over an extended period of time;
- the long-term performance of wells that were completed using different technologies;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;

- impacts of impairment write-downs on our financial statements;
- capital requirements for our operations and projects;
- our ability to continue to maintain the borrowing capacity under our Senior Secured Credit Facility (as defined below) or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- our ability to comply with restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- our ability to hedge, and regulations that affect our ability to hedge;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the availability and costs of sufficient gathering, processing, storage and export capacity in the Permian Basin and refining capacity in the U.S. Gulf Coast;
- the impact of repurchases, if any, of securities from time to time;
- the effectiveness of our internal controls over financial reporting and our ability to remediate a material weakness in our internal controls over financial reporting;
- our ability to maintain the health and safety of, as well as recruit and retain, qualified personnel necessary to operate our business;
- risks related to the geographic concentration of our assets; and
- our ability to secure or generate sufficient electricity to produce our wells without limitations.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various factors, including those set forth in this Annual Report under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

Part I

Item 1. Business

Except where the context indicates otherwise, amounts, numbers, dollars and percentages presented in this Annual Report are rounded and therefore approximate. Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum, Inc. and its subsidiaries at the applicable time, including former subsidiaries and predecessor companies, as applicable. For a full discussion of the development of our business, see "Part I, Item 1. Business" in our 2019 Annual Report on Form 10-K.

Overview

Laredo Petroleum, Inc., a Delaware corporation formed in 2011, is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2021, we had assembled 166,064 net acres in the Permian Basin, all of which were held in 398 sections. Our acreage is largely contiguous in the neighboring Texas counties of Borden, Howard, Glasscock, Reagan, Sterling and Irion. We have two wholly-owned subsidiaries, Laredo Midstream Services, LLC, a Delaware limited liability company ("LMS"), and Garden City Minerals, LLC, a Delaware limited liability company ("GCM"), and have identified one operating segment: exploration and production.

Business Strategy and 2021 Operational Highlights

Our strategy is to create long-term value through the acquisition of high-margin properties and the efficient development of those properties, combined with prudent balance sheet management and sustainable environmental practices. Beginning in late 2019, we began acquiring oil-weighted properties to the north and west of our existing Permian Basin acreage with the intention of quickly transitioning our development activities to these areas. We have significantly increased our oil production as a percentage of total production and improved our operating margin and, as a result, are on track for sustainable Free Cash Flow generation.

Our extensive operational history in the Permian Basin is a competitive advantage, enabling the efficient integration of acquired properties and attractive rates of return on development capital. Our geologic understanding of the Permian Basin allows us to safely maintain low drilling and completions and operating costs. Efficiencies are further improved by our contiguous acreage base and high working interest, enabling the drilling of longer horizontal wells and operational control of our development plans. Our development plan, driven by data gathered on more than 600 operated horizontal wells, employs conservative well-spacing that seeks to maximize both location count and well productivity.

In 2021, we made substantial progress executing our strategy, adding approximately 41,000 net acres of oil-weighted, high-margin inventory in Borden, Howard, and Glasscock counties, which are adjacent to our existing acreage in Howard and Glasscock counties. At year-end 2021, we held interests in approximately 66,500 net acres of oil-weighted inventory across such counties and have fully transitioned our development program to the more capital efficient acreage acquired since 2019. During the year, we also divested 37.5%, or approximately 94 million BOE, of our gas-weighted reserves primarily in Reagan and Glasscock counties, using the proceeds to fund a portion of the aforementioned acquisitions. Such moves optimize our capital investments by putting our low-cost structure to work on our oiliest acreage to produce the highest rate of return. With the sustained strength of commodity prices in 2021 and the realization of a long-term positive trend in drilling and completions efficiencies that have helped offset industry-wide service cost inflation, we have maintained a consistent development pace and realized improved expected returns on development capital.

We proactively manage our financial risks and maintain a strong capital structure. In 2021, we extended the maturity date of our Senior Secured Credit Facility to July 2025 and increased the borrowing base to $1 billion, substantially increasing our liquidity and flexibility. Additionally, we issued $400 million of senior notes maturing in 2029 at interest rates more than two percent lower than our notes due 2028 and used the proceeds to reduce the balance on our credit facility. We have historically hedged our production to protect cash flows, achieve strong rates of return on our capital investments and protect the Company in times of declining commodity prices. We entered 2021 with approximately 78% of our expected oil production protected and we will continue to seek hedging opportunities on a multi-year basis to further protect our capital plan, interest payments, and free cash flow generation.

We integrate best-in-class environmental, social and governance ("ESG") practices into our operations. In 2021, we enhanced our disclosure of key ESG metrics, publishing our inaugural ESG and Climate Risk Report, which covered 2019 operations and was aligned to the Sustainability Accounting Standards Board, the Task Force on Climate Related Financial Disclosures and the International Petroleum Industry Environmental Conservation Association frameworks. The report announced ambitious emissions reductions targets and outlined goals for reducing both greenhouse gas intensity and methane emissions, as well as eliminating routine flaring by 2025. Additionally, we published our 2021 ESG and Climate Risk Report, which covered 2020 operations, and further expanded our reporting to include industry frameworks provided by the American Petroleum Institute and the American Exploration and Production Council. In our 2021 report, we enhanced our disclosures by including climate-related scenario analysis, Scope 3 emissions estimates, and EEO-1 workforce diversity data. Furthermore, we described our pilot program for continuous emissions monitoring and began efforts to certify portions of our Howard and Glasscock County natural gas production as responsibly sourced through the Project Canary TrustWell™ Certification pilot project. Relatedly, for the second consecutive year, we incorporated environmental measures into our executive compensation program.

Our business strategy is both clear and sustainable. We will continue to focus on safely developing our highest return oil-weighted inventory while opportunistically adding more high-margin acreage as we seek to increase oil as a percentage of our production and improve our margins and profitability by taking advantage of our low-cost structure on more productive acreage. We are highly selective in the projects that we consider, and we will continue to monitor the market for strategic opportunities that we believe could be accretive and enhance shareholder value. These opportunities may take the form of acquisitions, divestitures, mergers, redemptions, equity or debt repurchases, or other similar transactions, any of which could result in the utilization of our Senior Secured Credit Facility and/or further accessing the capital markets.

Operating Areas

We focus our exploration, development and production efforts in one geographic operating area, the Permian Basin.

Well Data

We are currently focusing our development activities on horizontal drilling targets in the Wolfcamp A, Wolfcamp B and Lower Spraberry formations. Other targets for possible future development include the Upper Spraberry, Middle Spraberry, Wolfcamp C, and Wolfcamp D formations. As of December 31, 2021, we had an average working interest of 70% in Laredo-operated active productive wells and 66% in all wells in which Laredo has an interest, and our leases are 98% held by production. Laredo's working interest in operated active productive wells decreased significantly from previous years as a result of the 37.5% wellbore interest divestiture to an affiliate of Sixth Street Partners, LLC.

The following table sets forth certain information regarding productive wells as of December 31, 2021. Wells are classified as oil or natural gas wells according to the predominant production stream. All but thirteen of our wells are classified as oil wells, all of which also produce liquids-rich natural gas and condensate when in a producing status. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				
	Gross			Net	
	Vertical	Horizontal	Total	Total	Average WI %
Permian-Midland Basin:					
Operated	948	696	1,644	1,202	73 %
Non-operated	163	110	273	58	21 %
Total	1,111	806	1,917	1,260	66 %

Drilling Activity

On December 31, 2021, we had three drilling rigs drilling horizontal wells and two completions crews. We anticipate releasing one drilling rig and one completions crew by the end of first-quarter 2022 and remaining at two drilling rigs and one completions crew through year-end 2022. We will adjust our drilling rig count and/or completion crews to maximize efficiencies and cash flow. If we decrease our drilling rig count and/or completion crews, it will have a negative impact on our production. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources" and Note 15.b to our consolidated financial statements included elsewhere in this Annual Report for additional information.

The following table summarizes our drilling activity with respect to the number of wells completed and turned-in line for the periods presented. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Years ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	71	70.1	48	47.3	59	56.2
Dry	—	—	—	—	—	—
Total development wells	71	70.1	48	47.3	59	56.2
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	—	—	—	—	—	—

Sales volumes, revenues, prices and expenses history

The following table presents information regarding our oil, NGL and natural gas sales volumes, sales revenues, average sales prices, and selected average costs and expenses per BOE sold for the periods presented and corresponding changes for such periods. Our reserves and sales volumes are reported in three streams: crude oil, NGL and natural gas. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

(unaudited)	Years ended December 31, 2021	2020	2019	2021 compared to 2020 Change (#)	Change (%)
Sales volumes:					
Oil (MBbl)	11,619	9,827	10,376	1,792	18 %
NGL (MBbl)	8,678	10,615	9,118	(1,937)	(18)%
Natural gas (MMcf)	57,175	70,049	60,169	(12,874)	(18)%
Oil equivalents (MBOE)(1)(2)	29,827	32,117	29,522	(2,290)	(7)%
Average daily oil equivalent sales volumes (BOE/D)(2)	81,717	87,750	80,883	(6,033)	(7)%
Average daily oil sales volumes (Bbl/D)(2)	31,833	26,849	28,429	4,984	19 %
Sales revenues (in thousands):					
Oil	$ 805,448	$ 367,792	$ 572,918	$ 437,656	119 %
NGL	$ 191,591	$ 78,246	$ 100,330	$ 113,345	145 %
Natural gas	$ 150,104	$ 50,317	$ 33,300	$ 99,787	198 %
Average sales prices(2):					
Oil ($/Bbl)(3)	$ 69.32	$ 37.43	$ 55.21	$ 31.89	85 %
NGL ($/Bbl)(3)	$ 22.08	$ 7.37	$ 11.00	$ 14.71	200 %
Natural gas ($/Mcf)(3)	$ 2.63	$ 0.72	$ 0.55	$ 1.91	265 %
Average sales price ($/BOE)(3)	$ 38.46	$ 15.45	$ 23.93	$ 23.01	149 %
Oil, with commodity derivatives ($/Bbl)(4)	$ 52.09	$ 56.41	$ 54.37	$ (4.32)	(8)%
NGL, with commodity derivatives ($/Bbl)(4)	$ 10.55	$ 9.12	$ 13.61	$ 1.43	16 %
Natural gas, with commodity derivatives ($/Mcf)(4)	$ 1.56	$ 1.02	$ 1.05	$ 0.54	53 %
Average sales price, with commodity derivatives ($/BOE)(4)	$ 26.36	$ 22.50	$ 25.45	$ 3.86	17 %
Selected average costs and expenses per BOE sold(1)(2)					
Lease operating expenses	$ 3.42	$ 2.55	$ 3.08	$ 0.87	34 %
Production and ad valorem taxes	2.30	1.03	1.38	1.27	123 %
Transportation and marketing expenses	1.61	1.55	0.86	0.06	4 %
Midstream service expenses	0.12	0.12	0.15	—	— %
General and administrative (excluding LTIP)	1.54	1.29	1.63	0.25	19 %
Total selected operating expenses	$ 8.99	$ 6.54	$ 7.10	$ 2.45	37 %
General and administrative (LTIP):					
LTIP cash	$ 0.35	$ 0.06	$ —	$ 0.29	483 %
LTIP non-cash	$ 0.22	$ 0.22	$ 0.22	$ —	— %
Depletion, depreciation and amortization	$ 7.22	$ 6.76	$ 9.00	$ 0.46	7 %

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented in the years ended December 31, 2021, 2020 and 2019 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

(3) Price reflects the average of actual sales prices received when control passes to the purchaser/customer adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point.

(4) Price reflects the after-effects of our commodity derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured commodity derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to commodity derivatives that settled during the respective periods.

Reserves

In this Annual Report, the information with respect to our estimated proved reserves has been prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to the reporting dates presented.

The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of the date presented, and net average daily production presented on a three-stream basis for the period presented.

	December 31, 2021					Year ended December 31, 2021			
	Estimated proved reserves[1]			Producing wells		Average daily production			
	MBOE	% Oil	Net acreage	Gross	Net	(BOE/D)	% Oil	% NGL	% Natural gas
Permian-Midland Basin	318,640	38 %	166,064	1,917	1,260	81,717	39 %	29 %	32 %

(1) See "—Our operations—Estimated proved reserves" for discussion of the prices utilized to estimate our reserves.

Our estimated proved reserves as of December 31, 2021 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. See Note 6 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our Realized Prices. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net cash flows involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties. The following table sets forth additional information regarding our estimated proved reserves as of the dates presented:

	December 31, 2021	December 31, 2020
Proved developed:		
Oil (MBbl)	70,727	51,751
NGL (MBbl)	78,908	96,251
Natural gas (MMcf)	494,476	633,503
Total proved developed (MBOE)	232,048	253,586
Proved undeveloped:		
Oil (MBbl)	50,175	16,008
NGL (MBbl)	21,139	4,671
Natural gas (MMcf)	91,669	23,781
Total proved undeveloped (MBOE)	86,592	24,642
Estimated proved reserves:		
Oil (MBbl)	120,902	67,759
NGL (MBbl)	100,047	100,922
Natural gas (MMcf)	586,145	657,284
Total estimated proved reserves (MBOE)	318,640	278,228
Percent developed	73 %	91 %

Technology used to establish proved reserves

Under SEC rules, proved reserves are those quantities of oil, NGL and natural gas that 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. Reasonable certainty implies a high degree of confidence that the quantities of oil, NGL and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed reliable technologies that have been demonstrated to yield results with consistency and repeatability.

Qualifications of technical persons and internal controls over reserves estimation process

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Reserves Auditing Standards") and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2021, 2020 and 2019 included in this Annual Report. The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE Reserves Auditing Standards.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserve estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information.

From January through June of 2021, our Vice President of Planning and Business Development was the technical person primarily responsible for overseeing the preparation of our reserve estimates. He had more than 30 years of practical experience, with 30 years of this experience being in the estimation and evaluation of reserves. He held a Bachelors and Masters of Science in Petroleum Engineering from Texas A&M University. From July through December 31, 2021, following the departure of our Vice President of Planning and Business Development, our Director of Reserves became and continues to serve as the technical person primarily responsible for overseeing the preparation of our reserves estimates. She has more than 20 years of practical experience, with 7 years of this experience being in the estimation and evaluation of reserves. She has a Bachelors of Science in Petroleum Engineering from the Missouri University of Science and Technology. Both our former Vice President of Planning and Business Development and our Director of Reserves report to our Chief Financial Officer. Reserve estimates are reviewed and approved by our senior engineering staff, other members of senior management and our technical staff, our audit committee and our Chief Executive Officer.

Proved undeveloped reserves

We limit the portion of reserves categorized as "proved undeveloped" or "PUD" in order to emphasize operations on our most economic investments, maximize operational flexibility and maintain conservative assurance that all PUD locations will be converted despite potential commodity price volatility.

Our proved undeveloped reserves increased from 24,642 MBOE as of December 31, 2020 to 86,592 MBOE as of December 31, 2021. We estimate that we incurred $196 million of costs to convert 15,882 MBOE of proved undeveloped reserves from 38 locations into proved developed reserves in 2021. New proved undeveloped reserves of 65,621 MBOE were added during the year from (i) 12,645 MBOE from seven Spraberry and 22 new Wolfcamp locations and (ii) 52,976 MBOE from acquisitions in Borden, Howard, and Glasscock counties. 12,210 MBOE of positive revisions consisted of a net (i) 1,700 MBOE of negative revisions due to proved undeveloped locations that were removed due to change in the development plan, (ii) 7,609 MBOE of positive revisions from an increase in previously estimated quantities due to performance and price and (iii) 6,301 MBOE of positive revisions due to the inclusion of twelve undeveloped locations that were removed from reserves in a previous year due to pricing. A final investment decision has been made on all 155 proved undeveloped locations, and they are scheduled to be developed within five years from the date they were initially recorded.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2021 reserve report are $961.6 million. Based on this report and our PUD booking methodology, the capital estimated to be spent to develop the proved undeveloped reserves from spud date through production is $347.5 million in 2022, $202.2 million in 2023, $205.0 million in 2024, $172.7 million in 2025 and $16.3 million in 2026. Based on our anticipated cash flows and capital expenditures, as well as the availability of capital markets transactions, all of the proved undeveloped locations are expected to be drilled and completed from 2022 to 2026. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs, drilling and production results, technology, acreage position and availability and other economic and regulatory factors may lead to changes in development plans.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2021, including acreage HBP. A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		% HBP
	Gross	Net	Gross	Net	Gross	Net	
Permian-Midland Basin	198,783	163,128	4,384	2,936	203,167	166,064	98 %

The following table sets forth our gross and net undeveloped acreage as of December 31, 2021 that will expire over the next four years unless production is established within the spacing units covering the acreage or the lease is renewed, renegotiated or extended under continuous drilling provisions prior to the primary term expiration dates.

	Years ended December 31,							
	2022		2023		2024		2025	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian-Midland Basin	1,519	1,048	374	414	1,026	979	—	—

Of the total undeveloped acreage identified as potentially expiring over the next five years as of December 31, 2021, 2,355 net acres have associated PUD reserves included in our reserve report as of December 31, 2021, which we anticipate drilling to hold or renewing the associated leases. These PUD reserves represent 1% of our total PUD reserves as of December 31, 2021.

Of the total undeveloped acreage identified as potentially expiring over the next three years as of December 31, 2020, 3,642 net acres had associated PUD reserves included in our reserve report as of December 31, 2020. Of the total undeveloped acreage potentially expiring in 2021, 261 net acres were not retained through lease renewals or operations.

Marketing

We market the majority of production from properties we operate for both our account and the account of the other working interest owners. We sell substantially all of our production under contracts ranging from terms of one month to multiple years, all at monthly calculated market prices. We typically sell production to a relatively limited number of customers, as is customary in the exploration, development and production business; however, we believe that our customer diversification affords us optionality in our sales destination.

We are committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. The following table presents our material firm sale and transportation commitments as of December 31, 2021:

	Total	2022	2023	2024	2025 and after
Crude oil (MBbl):					
Sales commitments	10,470	8,660	1,810	—	—
Transportation commitments:					
Field	32,880	10,950	10,950	10,980	—
To U.S. Gulf Coast	67,960	13,675	12,775	12,810	28,700
Natural gas (MMcf):					
Sales commitments	69,188	15,466	11,300	8,332	34,090
Total commitments (MBOE)[(1)]	122,841	35,863	27,418	25,179	34,382

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

We have firm field transportation agreements that enable us or the purchasers of our oil production to move oil from our production area to major market hubs, including Colorado City, Texas; Midland, Texas; and Crane, Texas. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for our business. A portion of our commitments are related to transportation commitments extending into 2024 with Medallion Pipeline Company, LLC ("Medallion") under which Medallion provides firm transportation capacity from our established Reagan County and Glasscock County acreage for redelivery to various major market hubs. We also have a firm transportation agreement with BridgeTex Pipeline Company, LLC to move oil from Colorado City, Texas to the U.S. Gulf Coast. In 2018, we signed an agreement with Gray Oak Pipeline, LLC to initially transport 25,000 barrels of oil per day increasing to 35,000 barrels of oil per day of our production from Crane, Texas to the U.S. Gulf Coast. Our shipments under this contract began in the fourth quarter of 2019. We believe these commitments enhance our ability to move our crude oil out of the Permian Basin and give us access to multiple pricing points for the sale of our crude oil.

We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. See Note 15.c to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our transportation commitments.

We believe that we could sell our production to numerous companies, so that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition and results of operations solely by reason of such loss. For discussion on purchasers that individually accounted for 10% or more of each (i) oil, NGL and natural gas sales and (ii) sales of purchased oil in at least one of the years ended December 31, 2021, 2020 and 2019, see Note 14 to our consolidated financial statements included elsewhere in this Annual Report. See also "Item 1A. Risk Factors—Risks related to our business—The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results."

Title to properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under oil and gas leases or net profit interests.

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGL and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, the production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The State of Texas has regulations governing environmental and conservation matters, including provisions for the pooling of oil and natural gas properties, the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells (including the proration of production to the market demand for oil, NGL and natural gas), the regulation of well spacing, the handling and disposal or discharge of waste materials and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, NGL and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by, among other things, requiring permits and bonds for the drilling and operation of wells and regulating the location of wells, method of drilling and casing wells, surface use and restoration of properties upon which wells are drilled and plugging and abandonment of wells. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the natural gas industry are regularly considered by the current administration, Congress, the states, the Environmental Protection Agency ("EPA"), the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective, under the current or any future administration.

Oil and gas pipelines

Our oil and gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016", which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. On October 1, 2019, the PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside high consequence areas. The rules, once effective, also extend reporting requirements to certain previously unregulated hazardous liquid gravity and rural gathering lines. Also, on November 15, 2021, the PHMSA published a final rule extending reporting requirements to all onshore gas gathering operators and establishing a set of minimum safety requirements for certain gas gathering pipelines with large diameters and high operating pressures. Additional rulemakings are anticipated, including rulemakings to adjust repair criteria for gas transmission lines, to require inspection of gas pipelines following extreme events, and to strengthen integrity management assessment requirements. Also, on June 7, 2021, the PHMSA issued an advisory bulletin reminding pipeline owners and operators that, pursuant to legislation signed into law in December 2020, they must take several steps to eliminate hazardous leaks and minimize releases of natural gas by December 27, 2021. These requirements could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operation or financial position. In addition, any material penalties or fines issued to us under these or other statutes, rules, regulations or orders could have an adverse impact on our business, financial condition, results of operation and cash flow.

States are largely pre-empted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards, and many states have undertaken responsibility to enforce the federal standards. The RRC is the agency vested with intrastate natural gas pipeline regulatory and enforcement authority in Texas. The Commission's regulations adopt by reference the minimum federal safety standards for the transportation of natural gas. In addition, on December 17, 2019, the Commission adopted rules requiring that operators of gathering lines take "appropriate" actions to fix safety hazards.

Environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

Certain of these laws and regulations impose strict liability (i.e., no showing of "fault" is required) that, in some circumstances, may be joint and several. Public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and clean-up requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (referred to as "CERCLA" or the "Superfund law") and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties. Finally, it is not uncommon for neighboring landowners and other third parties to file common law based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and clean-up costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from a violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps").

The scope of waters regulated under the CWA has fluctuated in recent years. On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. However, on October 22, 2019, the agencies repealed the 2015 rules, and on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rules, and significantly reduced the waters subject to federal regulation under the Clean Water Act. On August 30, 2021, a federal court struck down the replacement rule and on December 7, 2021, the EPA and the Corps published a proposed rule that would put back into place the pre-2015 definition of “waters of the United States,” updated to reflect Supreme Court decisions, while the agencies continue to consult with stakeholders on future regulatory actions. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. The State of Texas also maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil.

Hydraulic fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process for our producing properties in Texas because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. While hydraulic fracturing is not required to maintain any of our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the provided non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved undeveloped reserves associated with future completion, recompletion and refracture stimulation projects require hydraulic fracturing.

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We have and continue to follow standard industry practices and applicable legal requirements. These protective measures include setting surface casing at a depth sufficient to protect fresh water formations and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This well design is intended to eliminate a pathway for the fracturing fluid to contact any aquifers. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Injections rates and pressures are monitored in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Our hydraulic fracturing operations are designed to be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into the approved disposal wells. We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracking operations, we endeavor to maximize the utilization of recycled flowback/produced water via our owned and operated recycling facilities in Glasscock and Reagan County or via contractual arrangements with third parties in Howard County.

The SDWA regulates the underground injection of substances through the Underground Injection Control Program (the "UIC"). However, hydraulic fracturing is generally exempt from regulation under the UIC, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC. On February 12, 2014, the EPA published a revised UIC Program permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how Class II regulations may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing and require public disclosure of the chemicals used in the fracturing process.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. We cannot predict the impact that these actions may have on our business at this time, but further regulation of hydraulic fracturing activities could have a material impact on our business, financial condition and results of operation.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On March 28, 2017, the Trump Administration issued an executive order directing the BLM to review the rule, and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. At this time, it is uncertain when, or if, the hydraulic fracturing rule will be implemented, and what impact it would have on our operations.

Furthermore, there are certain governmental reviews either under way or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, beginning February 1, 2012, companies were required to disclose to the RRC and the public the chemical components used in the hydraulic fracturing process, as well as the volume of water used. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid 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. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits and temporarily suspend operations for waste disposal wells and, in September 2021, the RRC curtailed the amount of water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin and has since indefinitely suspended some permits there and expanded the restrictions to other areas. These restrictions on the disposal of produced water could result in increased operating costs, forcing us or our service providers to truck produced water, recycle it or pump it through the pipeline network or other means, all of which could be costly. In addition, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Air quality

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including production facilities, salt water disposal facilities, and compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources and emissions from specific sources such as tanks, engines, dehydration units, and heaters. Also, on June 3, 2016, the EPA published a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule clarified the term “adjacent” and defined when sources are required to be aggregated. The consequences of these requirements are that smaller sites may need to be combined, triggering more stringent air permitting processes and requirements. Current air permitting regulations require us to obtain pre-approval for the construction or modification of projects or facilities expected to produce or increase air emissions. Once obtained these air permits require compliance with strict and stringent requirements and utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain air permits and emission control equipment prior to construction requires timely planning to ensure that the development of oil and natural gas projects is not delayed.

In August 2012, the EPA published New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants for oil and natural gas production, processing, transmission, and storage operations. The rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, pneumatic controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. This rule was promulgated and implemented to reduce emissions from volatile organic compounds ("VOC"). On June 3, 2016 the EPA published additional standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector, including Leak Detection and Repair ("LDAR") programs, emission controls for tanks, verification of closed vent systems, and compressor requirements. Regulation of oil and natural gas facilities continues to expand and become more rigorous. Most recently, on November 15, 2021, the EPA published a proposed rule for oil and natural gas facilities that will expand control requirements, increase LDAR inspection frequencies, prohibit venting of natural gas in certain situations, require equipment retrofits, and regulate older facilities.

In addition, on November 18, 2016, the BLM finalized a waste prevention rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. On March 28, 2017, the Trump Administration issued an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. On September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens." However, a federal court struck down the scaled-back rule on July 15, 2020, and shortly thereafter, on October 8, 2020, another federal court struck down the 2016 waste prevention rule. At this time, it is uncertain when, and to what extent, the waste prevention rule will be implemented, and what impact it will have on our operations.

The above standards, as well as any future laws and their implementing regulations, require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions and impose stringent air permit requirements. These regulations also mandate the use of specific equipment or technologies to minimize, eliminate, or control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We have incurred additional capital expenditures to ensure compliance with these new regulations as they come into effect. We may also be required to incur additional capital expenditures in the next few years for air pollution control equipment in connection with complying with new air regulations, maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations and has the potential to delay the development of oil and natural gas projects.

"Greenhouse gas" emissions

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases ("GHGs"). The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce GHG emissions primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. Also, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and gas operations. In addition, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. Although the United States withdrew from the Paris Agreement, effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which took effect on February 19, 2021. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its GHG emissions by 50-52 percent below 2005 levels in 2030. In November 2021, in connection with the 26th Conference of the Parties in Glasgow, Scotland, the United States and other world leaders made further commitments to reduce GHGs, including reducing global methane emissions by at least 30% by 2030. Relatedly, many state and local leaders have stated their intent to intensify efforts to support the international climate commitments.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds 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. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Occupational Safety and Health Act

Certain of our operations are subject to applicable requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that certain information be provided to employees, state and local government authorities and citizens.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. Any exploration and production activities, as well as proposed exploration and development plans, on federal lands would require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If previously unprotected species, such as the dunes sagebrush lizard, are designated as endangered or threatened, or if we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

We believe we are in substantial compliance with currently applicable environmental federal, state and local laws and regulations and that we hold all necessary, valid and up-to-date permits, registrations and other authorizations required under such laws and regulations or are in the process of obtaining such items. However, current regulatory requirements may change, currently unforeseen incidents may occur or past non-compliance with laws or regulations may be discovered, and such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance. Although we have not experienced any material adverse effect from compliance with environmental requirements and believe that the current costs of compliance are appropriately reflected in our budget, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws and regulations or environmental remediation matters during the years ended December 31, 2021, 2020 or 2019.

Regulation of derivatives

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions (the "Prudential Regulators") adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

The CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including rules (the "Adopted Derivatives Rules") (i) requiring clearing of hedges, or swaps, that are subject to the Dodd-Frank Act (currently, only certain interest rate and credit default swaps, which we do not presently have (the "Mandatory Clearing Rule"), and also establishing an "end user" exception to the Mandatory Clearing Rule (the "End User Exception"), (ii) setting forth collateral requirements in connection with swaps that are not cleared (the "Margin Rule") and also an exception to the Margin Rule for end users that are not financial end users (the "Non-Financial End User Exception") and (iii) imposing position limits on certain futures contracts, including the NYMEX "Henry Hub" gas contract and "Light Sweet Crude" oil contract, and economically equivalent swaps (the "Position Limit Rule"). The Position Limit Rule took effect March 15, 2021 and the position limits, other than those for economically equivalent swaps provided for in the Position Limit Rule, took effect on January 1, 2022; the position limits for economically equivalent swaps will take effect on January 1, 2023. The Position Limit Rule provides an exemption from the position limits for swaps that constitute "bona fide hedging positions" within the definition of such term under the Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and our existing and anticipated hedging positions constitute "bona fide hedging positions" under the Position Limit Rule, and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Position Limit Rule, so we do not expect to be directly affected by any such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts, collectively the "Foreign Regulations"), which may apply to our transactions with counterparties subject to such Foreign Regulations (the "Foreign Counterparties") and the U.S. adopted law and rules (the "U.S. Resolution Stay Rules") clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation.

Human Capital

The *Laredo Way* is a path designed for our employees to experience mutual respect, openness, honesty and a spirit of trust and collaboration while employed by Laredo. Laredo's key human capital objectives are to attract, retain, motivate and develop the highest quality talent possible. To support these objectives, we support and encourage an inclusive work environment to help our employees attain their highest level of productivity, creativity and efficiency. Diverse and sound ideas, approaches and individual experiences are essential features of inclusion. We foster an environment of safety and inclusion through the implementation of our Code of Conduct and Business Ethics and annual anti-harassment training. We firmly believe that everyone at Laredo contributes to our success.

Workforce Composition

As of December 31, 2021, we employed 273 full-time employees, 133 of which were based in our field offices. The remaining (nearly one-half) of our employees possess technical and professional backgrounds, often holding advanced degrees. Our professional staff includes geoscientists, petroleum and chemical engineers, land women and men, accountants, computer and data scientists, financial analysts, lawyers, human resource specialists and many more.

Diversity and Inclusion

We believe that a diverse workforce will help our organization better accomplish our mission. To increase our hiring of traditionally underrepresented personnel and women, Laredo proactively sources open positions on job sites specifically focused on diversity. This allows us to gain candidates from underrepresented talent pools to help fill our positions. At the end of our fiscal year 2021, our workforce consisted of:

- 26% diverse based on ethnicity
- 27% diverse based on gender
- 4% US military veterans
- 34% women in professional roles or higher

Laredo strives to provide a comfortable and progressive workplace where communication is open and problems can be discussed and resolved in a mutually respectful atmosphere. We take into account individual circumstances and the individual employee. Working together, we are stronger, and we will continue to honor diversity and inclusion as key values of the *Laredo Way*.

Health and Safety

Most importantly, we know that an engaged, healthy, safe and well-trained workforce is key to our world-class culture and helps us accomplish our strategic goals. Safety is a core part of Laredo's culture, and we pride ourselves on our commitment to conduct all operations in a safe manner. As we continue to adapt to new ways of working during the COVID-19 pandemic, we will continue to operate responsibly while always putting the safety and well-being of our employees, their families and our communities first. We have implemented several measures for all employees, such as keeping pay and benefits whole for those who are finding their work routines disrupted by the pandemic and keeping in-person or onsite gatherings for essential and safety purposes only. We are monitoring the situation closely and are committed to prioritizing the health and safety of our people and communities above all else.

Safety is a core part of Laredo's culture, and we pride ourselves on our commitment to conduct all our operations in a safe manner. Although we are always striving for zero incidents, we are proud of our record of safe operations. Our safety best practices include: annual training, pre-job safety meetings, on-site contractor management and safety personnel, hazard hunts, bi-annual external safety audits, stop work authority, after action review and root cause analysis.

Total Rewards

To attract and retain exceptional talent, we provide our employees a comprehensive total rewards program, which includes a comprehensive benefits offering and competitive compensation package. We recognize that by offering relevant and innovative total rewards programs to our employees, we send a message that we are listening to their needs and promoting flexibility as well as sound health and wellness opportunities. In addition to competitive salaries, we offer both short and long term incentive programs, company-matched 401K contributions, flexible working schedules and many more employee-focused programs. Demonstrating our commitment to our employees' health and well-being, highlighted below are several benefits of our total rewards program.

- ***Healthcare****:* We provide over 80% of health insurance premiums to ensure our employees and their families have access to affordable healthcare.
- ***Fitness***: We provide an onsite fitness center for our Tulsa employees and access to local fitness facilities for our field personnel.
- ***Family***: We provide flexible work schedules to enable our employees to attend important family events during the workday and onsite lactation rooms to provide mothers with a calm and private space.
- ***Trust***: We provide a hotline for employees and contractors to report grievances without retaliation and allow us to review and adjust policies, where necessary.

Training

We recognize and support our employees' desire to continue to learn and develop. We offer opportunities both internally and externally to participate in learning programs. We offer tuition reimbursement benefits for extended educational learning opportunities. Additionally, we have a robust training program for our Lease Operators and Field Technicians that allows for consistency in our processes and gives the management team clarity when considering field employees for promotional opportunities. Administration of this program is a joint effort between leadership on the Production team and the Learning and Development staff that allows us to intentionally train our employees with the goal of promoting from within for all promotions in the field. Laredo prides itself on the ability to promote our great employees.

Attracting, retaining and developing our people is crucial to all aspects of our long-term success and is central to our long-term strategy. We will continue to invest in our employees to ensure that we continue building an inclusive culture that inspires loyalty and encourages innovation. By working together and focusing on our employees, we will continue to honor diversity and inclusion as key values of the Laredo Way.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC, which are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov. Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI."

We also make available on our website (http://www.laredopetro.com) all of the documents that we file with the SEC and amendments to those reports, including related exhibits and supplemental schedules, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Conduct and Business Ethics, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines, Policy Statement Regarding Related Party Transactions and the charters of our audit committee, compensation committee, finance committee, and nominating and corporate governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our executive office. Information contained on our website is not incorporated by reference into this Annual Report. We intend to disclose on our website any amendments or waivers to our Code of Conduct and Business Ethics or Code of Ethics for Senior Financial Officers that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Summary Risk Factors

The following is a summary of the material risks and uncertainties we have identified, which should be read in conjunction with the more detailed description of each risk factor contained below.

Risks related to our business

- Effects of the COVID-19 pandemic and responses;
- Volatility in prices for oil, NGL and natural gas;
- Risks associated with spacing, drilling and completions techniques;
- Competition in the oil and gas industry;
- Risks in connection with acquisitions and disposition of assets;
- Risks associated with recent transactions and exposure to contingent liabilities;
- Changes in market/investor priorities;
- Uncertainties associated with estimating reserves and future net cash flows;
- Our ability to replace our oil and natural gas reserves;
- Insufficient transportation capacity in the Permian Basin and other risks associated with transportation and storage;
- Our level of success in development and production activities;
- The timing and occurrence of drilling future wells;
- Uncertainties associated with our use of 2D and 3D seismic analytics and other data;
- Inability of significant customers to meet their obligations;
- Unavailability or high cost of additional oilfield services;
- Cybersecurity threats and other disruptions in our electronic systems;
- Hydrocarbon price volatility as a result of Russian activities in Ukraine;
- Our ability to attract, train and retain qualified personnel;
- New operational and technical issues;
- Conservation measures and market perception towards the Oil and Natural Gas Industry;
- The geographic concentration of our operations;
- Uncertainties associated with an ownership change;
- Incurrence of substantial losses and liability claims as a result of our oil and gas operations, and risks our insurance may be inadequate to protect us against these losses;
- Failure to effectively and timely address the energy transition; and
- Risks associated with our targets and initiatives related to sustainability and emissions reduction.

Risks related to our financing and indebtedness

- Our ability to obtain needed capital or financing;
- Our ability to obtain future hedges and effectiveness of our commodity derivative activities;

- Incurrence of significant additional amounts of debt;
- Cost and ability to access capital;
- Interest rate risk as a result of borrowings under our Senior Secured Credit Facility;
- Our ability to generate cash;
- Reductions in our borrowing base under our Senior Secured Credit Facility;
- Losses from operations; and
- Debt covenants that limit our flexibility in operating our business.

Risks related to regulation of our business

- Our ability to drill new allocation wells;
- Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells;
- Availability, use and disposal of water;
- Legislation or regulatory initiatives addressing seismic activity;
- Potential changes in the jurisdictional characterization of some of our assets;
- Adoption of climate change legislation or regulations restricting emissions of “greenhouse gases” and potential physical effects of climate change;
- Significant delays, costs and liabilities as a result of environmental, health and safety requirements;
- Designation as “critical infrastructure” could subject us to additional regulation;
- Derivatives reform legislation and related regulations;
- Changes in tax laws and regulations; and
- Restrictions on drilling activities intended to protect certain species of wildlife.

Risks related to our common stock

- Provisions in our amended and restated certificate of incorporation, amended and restated bylaws and Delaware state law potentially delaying a change in control;
- Availability of shares for sale in the future; and
- We have no plans to pay and are currently restricted from paying dividends on our common stock.

Risks related to our business

Our business and operations have been and will likely continue to be affected by the recent COVID-19 pandemic and responses.

The spread of the COVID-19 coronavirus caused, and is continuing to cause, disruptions in the worldwide and U.S. economy. There are many variables and uncertainties regarding the COVID-19 pandemic, including the emergence, contagiousness and threat of new and different strains of the virus and their severity; the effectiveness of treatments or vaccines against the virus or its new strains; the extent of travel restrictions, business closures and other measures that are or may be imposed in affected areas or countries by governmental authorities; disruptions in the supply chain; an increasingly competitive labor market due to a sustained labor shortage or increased turnover caused by the COVID-19 pandemic; increased logistics costs; additional costs due to remote working arrangements, adherence to social distancing guidelines and other COVID-19-related challenges; and decreases in the price of oil due to remote working arrangements. Further, there remain increased risks of cyberattacks on information technology systems used in remote working environment; increased privacy-related risks due to processing health-related personal information; absence of workforce due to illness; the impact of the pandemic on any of our contractual counterparties; and other factors that are currently unknown or considered immaterial. It is difficult to assess the ultimate impact of the COVID-19 pandemic on our business, financial condition and results of operations.

As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have been required to, and may be required to further, write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations–Pricing and reserves" and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Oil, NGL and natural gas prices are volatile. Volatility in oil, NGL and natural gas prices has adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Commodity prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, NGL and natural gas has been volatile and will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. See "Cautionary Statement Regarding Forward-Looking Statements" for a list of the factors that significantly impact our business and could impact our business in the future, including those specifically related to pricing and production.

Lower oil, NGL and natural gas prices have reduced, and may in the future continue to reduce, our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A further decrease in oil, NGL and natural gas prices could render uneconomic a large portion of our exploration, development and exploitation projects. This has already resulted in us having to make significant downward adjustments to our estimated proved reserves, and we may need to make further downward adjustments in the future. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur by May 1 and November 1 of each year, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two scheduled redetermination dates and in other specified circumstances. A reduced borrowing base could trigger repayment obligations under our Senior Secured Credit Facility. Also, lower oil, NGL and natural gas prices would likely cause a decline in our stock price.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our rate of return, cash flows from operations and shareholder value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our rate of return, cash flows from operations and shareholder value. However, due to many factors, including some beyond our control, there is no guarantee that we will be able to find the optimal plan or one that provides continuous improvement. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our production results, financial performance, stock price and net asset value.

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

Our ability to acquire additional locations and to find and develop reserves in the future may depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive, concentrated geographic environment for acquiring properties, marketing oil, NGL and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil, NGL and natural gas industry, especially in our focus areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil, NGL and natural gas properties and exploratory locations and to evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

We may be subject to risks in connection with acquisitions and disposition of assets.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, NGL and natural gas prices and their applicable differentials;
- timing of development;
- capital and operating costs; and
- potential environmental and other liabilities.

The successful disposition of assets requires an assessment of several factors, including historical operations, potential environmental and other liabilities and impact on our business. The accuracy of these assessments is inherently uncertain. Our assessment will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller or buyer may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire or sell assets on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller or buyer will not be able to fulfill its contractual obligations. Problems with assets we acquire or dispose of could have a material adverse effect on our business, financial condition and results of operations.

Acquisitions may not achieve the intended results and our results may suffer if we do not effectively manage our expanded operations following such transactions.

Some of the assumptions that we have made, such as the nature of assets to be acquired, may not be realized. There could also be undisclosed or unknown liabilities and unforeseen expenses associated with the acquisition that were not discovered in the due diligence review conducted by us prior to entering into the transaction agreements.

We may use more cash and other financial resources on integration and implementation activities than we expect. We may not be able to successfully integrate the assets acquired into our existing operations or realize the expected economic benefits of the acquisition, which may have a material and adverse effect on our business, financial condition and results of operations.

In instances where a portion of the acreage we are acquiring is undeveloped, our plans, development schedule and production schedule associated with the acreage may fail to materialize. As a result, our investment in these areas may not be as economic as we anticipate, and we could incur material write-downs of unevaluated properties.

Recent transactions may expose us to contingent liabilities.

We have agreed to indemnify the sellers of assets in recent transactions against certain liabilities related to (i) production, processing and other imbalances, (ii) obligations to pay working interests and related payments, (iii) obligations for plugging and abandonment of applicable wells and (iv) certain other items. In addition, we have agreed to indemnify the buyer of assets for breaches of certain specified fundamental representations and warranties and failure to perform covenants or obligations contained in the respective transaction agreement, subject to certain limitations, and certain other indemnities.

Our indemnification obligations are, in some cases, subject to limitations, but the amount of our maximum exposure could be material. In some instances, our indemnification obligations are not subject to any limitations. Significant indemnification claims by such sellers or buyers could materially and adversely affect our business, financial condition and results of operations.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With historical volatility in oil and natural gas prices and the likelihood that rising interest rates will increase the cost of borrowing, capital efficiency and free cash flow from earnings have become the key drivers for energy companies, particularly shale producers. Such shifts in focus sometimes require changes in planning and resource management, which may not occur instantaneously. Any delay in responding to such changes in market sentiment or perception may result in the investment community having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which may have a negative impact on the price of our common stock.

Estimating reserves and future net cash flows involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties.

The reserves data included in this Annual Report represent estimates. Reserves estimation is a subjective process of evaluating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to specific locations for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a five-year period.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including more rapid production declines than previously expected and many other factors beyond the control of the operator. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. Production declines may be rapid and irregular when compared to a well's initial production or initial estimates. In addition, the estimates of future net cash flows from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also trigger impairment losses on certain properties, which would result in a non-cash charge to earnings. See Note 19.d to our consolidated financial statements included elsewhere in this Annual Report.

Unless we replace our oil, NGL and natural gas production, our reserves and production will continue to decline, which would adversely affect our future cash flows and results of operations.

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

Insufficient transportation capacity in the Permian Basin, and the challenges to alleviating such transportation constraints, could cause significant fluctuations in our realized oil prices and our results of operations.

In our area of operation, the Permian Basin has been characterized by periods when oil and/or natural gas production has surpassed local transportation capacity, resulting in substantial discounts to the price received for commodity prices quoted for WTI oil and Henry Hub natural gas. The expansion and construction of pipeline facilities are affected by the availability and costs of necessary equipment, supplies, labor and other services, as well as the length of time to complete such projects. In addition, these projects can be affected by changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil and natural gas and any materials or products used to expand or construct pipeline facilities, such as certain imported steel mill products that may be subject to a 25% tariff. All of these factors could negatively impact our realized oil prices, as well as actual results of our operations.

The marketability of our production is dependent upon transportation, processing and storage, certain of which we do not control. If these services are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil, NGL and natural gas production depends on a variety of factors, including the availability, proximity, capacity and quality constraints of transportation, compression, natural gas processing, fractionation, export terminals and storage facilities owned by us or third parties. We do not control third-party facilities and pipelines that may be utilized for the transportation to market of the products originating at our leases. Our failure to provide or obtain such services on acceptable terms could materially harm our business.

Insufficient production from our wells to support the construction of pipeline facilities by third parties or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGL and natural gas and thereby cause a significant interruption in our operations. If we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or specifications or encounter production-related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, NGL and natural gas produced from our fields, could materially and adversely affect our financial condition and results of operations.

A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.

A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of extreme weather conditions, such as the freezing of wells and pipelines in the Permian Basin or a decision by the Electric Reliability Council of Texas ("ERCOT") to implement statewide electricity blackouts due to supply/demand imbalances in the electricity grid caused by the extreme cold weather, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes. Alternatively, we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.

In addition, we have entered into agreements with third party pipelines and purchasers that require us to deliver for transportation or sale minimum amounts of oil and natural gas. Pursuant to these agreements, we must deliver specific amounts of oil or gas over the next eight years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.

The potential drilling locations that we have tentatively internally identified for our future wells will be drilled, if at all, over many years. This makes them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Although our management team has established certain potential drilling locations as a part of our long-range development plan, our ability to drill and develop these locations depends on a number of uncertainties, including oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, our ability to leverage our data and development experience, the availability of drilling services and equipment, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have currently identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. As such, it is likely that our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

Our use of 2D and 3D seismic, analytics and other data is subject to interpretation and may not accurately identify the presence of oil, NGL and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data, analytics and other data that provide either visualization techniques and/or statistical analyses are only probability and estimation tools and do not ensure the existence of or the amount of hydrocarbons. We employ 3D seismic technology on certain of our projects, which is still relatively unproven. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

Our oil, NGL and natural gas production sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Certain purchasers individually account for 10% or more of our oil, NGL and natural gas sales in a given year. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. See Notes 2.d and 14 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our accounts receivable and credit risk, respectively.

The unavailability or high cost of additional oilfield services, including personnel, drilling rigs, equipment and supplies, as well as fees for the cancellation of such services, could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for and availability of qualified and experienced personnel to drill and complete wells and conduct field operations, including, but not limited to, frac crews, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling and workover rigs, pipe, sand, water and equipment as demand for such items has increased along with the number of wells being drilled. We have committed in the past, and we may in the future commit, to drilling rig contracts with various third parties that contain penalties for early terminations. These penalties could negatively impact our financial statements upon contract termination. Shortages in rigs, crews, supplies and equipment, as well as related fees could result in delays or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our business could be negatively impacted by disruption of electronic systems, security threats, including cyber-security threats, and other disruptions.

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

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

Our business could be negatively impacted by hydrocarbon price volatility as the result of, or as a result of the threat of, Russian activities in Ukraine and as the result of, or as a result of the threat of, Russia expanding its production of oil and gas to finance its activities in Ukraine and destabilize world energy markets.

Our revenues and our profitability are heavily dependent on the prices we receive from our sales of oil and natural gas. Oil prices are particularly sensitive to actual and perceived threats to global political stability and to changes in production from OPEC member states. An actual increase, or the threat of an increase, in Russian activities in Ukraine could lead to increased volatility in global oil and gas prices and increases in oil production by Russia to finance its activities in Ukraine or to destabilize global oil and gas prices could reduce the price we receive from our sales of oil and natural gas and adversely affect our profitability.

The loss of senior management or technical personnel and the failure to attract, train and retain qualified personnel could adversely affect our operations.

Effective succession planning is important to our long-term success. Failure to ensure effective transfer of knowledge and smooth transitions involving senior management and technical personnel could hinder our strategic planning and execution and could have a material adverse impact on our operations. We do not maintain any key-man or similar insurance for any officer or other employee.

We may not always foresee new operational/technical issues as new technology enables greater operational capabilities.

The unconventional oil and natural gas industry has seen a large increase in new technologies to enhance all aspects of operations. This has arguably accelerated as a result of the extended downturn in commodity prices, forcing companies to find new ways to more efficiently produce oil and natural gas. While such technologies can and often ultimately enhance operations, production and profitability, the utilization of such technologies, especially in their early phases, may result in unforeseen consequences and operational issues, resulting in negative consequences.

Conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices, and the increased competitiveness of alternative energy sources such as electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. In the past, equity returns in the sector versus other industry sectors have led to lower oil and natural 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 natural gas sector based on social and environmental considerations. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. With the volatility in oil and natural gas prices, and the likelihood that interest rates will rise in the near term, increasing the cost of borrowing, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially shale producers. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

The impact of the changing demand for oil and natural gas services and products, together with a change in investor sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, if we are unable to achieve the desired level of capital efficiency or free cash flow within the timeframe expected by the market, our stock price may be adversely affected.

Our producing properties are in a concentrated geographic area, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Permian Basin. As of December 31, 2021, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional transportation constraints, supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing and storage capacity constraints, market limitations, water shortages, interruption of the processing or transportation of oil or natural gas, as well as impacts from extreme weather or other natural disasters impacting the Permian Basin, such as the freezing of wells and pipelines in the Permian Basin or a decision by ERCOT to implement statewide electricity blackouts due to supply/demand imbalances in the electricity grid caused by the extreme cold weather.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carryforwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2021, we had federal net operating loss ("NOL") carryforwards totaling $2.1 billion and state of Oklahoma NOL carryforwards totaling $34.6 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, to which Oklahoma conforms, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

In addition, as a result of a comprehensive tax reform bill commonly referred to as the Tax Cuts and the Jobs Act (the "Tax Act"), NOLs arising before January 1, 2018, and NOLs arising on or after January 1, 2018, are subject to different rules. NOLs arising before January 1, 2018, can generally be carried forward to offset future taxable income for a period of 20 years. Any NOL arising on or after January 1, 2018, while subject to additional limitations, can generally be carried forward indefinitely. Our ability to use our NOLs during this period will be dependent on our ability to generate taxable income, and the NOLs could expire before we generate sufficient taxable income. As of December 31, 2021, based on evidence available to us, including projected future cash flows from our oil, NGL and natural gas reserves and the timing of those cash flows, we believe a portion of our NOLs is not fully realizable. As a result, as of December 31, 2021, a valuation allowance has been recorded against our net deferred tax assets. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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

We could be impacted by the outcome of pending litigation as well as unexpected litigation or proceedings. Certain litigation claims may not be covered under our insurance policies, or our insurance carriers may seek to deny coverage. Because we cannot accurately predict the outcome of any action, it is possible that, as a result of pending and/or unexpected litigation, we will be subject to adverse judgments or settlements that could significantly reduce our earnings or result in losses. See "Item 3. Legal Proceedings" for a description of our pending litigation.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- disagreements regarding the royalty due to our royalty owners;
- personal injuries and death;
- electronic system disruption and cyber-security threats;
- natural disasters; and
- terrorist attacks targeting oil, NGL and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;

- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The impact of litigation as well as the occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Failure to effectively and timely address the energy transition could negatively impact our operations, business and financial condition.

Effectively addressing the energy transition may require adapting our operations to changing local, state and federal requirements. While soliciting feedback from investors and other stakeholders to develop solutions to achieve our emissions targets may aide in effectively addressing the energy transition, should the transition occur faster than anticipated, or in a manner that we do not anticipate, demand for our products may be adversely affected. Furthermore, if we fail to effectively implement our emissions reduction strategy, or if investors or financial institutions shift funding away from companies in the oil and natural gas industry, our access to capital or the market for our securities may be negatively impacted.

Our targets related to sustainability and emissions reduction initiatives, including our public statements and disclosures regarding them, may expose us to numerous risks.

We have developed, and will continue to develop, targets related to ESG initiatives, including our emissions reduction targets and strategy. Public statements related to these initiatives reflect our current plans and are not a guarantee the targets will be achieved or achieved on the stated timeline. Our efforts to research, establish, accomplish, and accurately report on these targets may expose us to operational, reputational, financial, legal, and other risks. Our ability to achieve our stated targets, including emissions reductions, is subject to numerous factors and conditions, some of which are outside of our control.

Our business may face increased scrutiny from investors and other stakeholders related to our ESG initiatives, including our publicly announced targets, as well as our methodologies and timelines for pursuing those initiatives. If our ESG initiatives do not meet evolving investor or other stakeholder expectations and standards, our reputation, ability to attract or retain employees, and attractiveness as an investment or business partner may be negatively impacted. Similarly, our failure to achieve our announced targets or comply with ethical, environmental, or other standards, including reporting standards, may adversely impact our business. Furthermore, failure to achieve these targets within the announced timelines, or at all, may adversely affect our business or reputation, or may expose us to government enforcement actions or private litigation.

Risks related to our financing and indebtedness

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development, marketing, transportation and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. We do not have commitments from anyone to contribute equity capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil, NGL and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional capital could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, NGL and natural gas production or reserves and, in some areas, a loss of properties.

Currently, we receive a level of cash flow stability as a result of our hedging activity. To the extent we are unable to obtain future hedges at beneficial prices or our commodity derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, we enter into commodity derivative instrument contracts for a portion of our oil, NGL and natural gas production, including puts, swaps, collars, basis swaps and, in the past, call spreads. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statements of operations as gain (loss) on derivatives. Gain (loss) on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments, including a decrease in earnings if the price of commodities increases above the price of hedges that we have in place. As our current hedges expire, there is a significant uncertainty that we will be able to put new hedges in place that satisfy our hedge philosophy.

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

- production is less than the volume covered by the commodity derivative instruments;
- the counter-party to the commodity derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

In addition, government regulation may adversely impact our ability to hedge these risks.

For additional information regarding our hedging activities, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 10 and 11 to our consolidated financial statements included elsewhere in this Annual Report.

We may incur significant additional amounts of debt.

As of December 31, 2021, we had total long-term indebtedness of $1.44 billion. We may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our senior unsecured notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the senior unsecured notes apply only to debt that constitutes indebtedness under the indentures. However, such increased debt may reduce the amount of outstanding debt allowed under the Senior Secured Credit Facility.

Increases in our cost of and ability to access capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow and/or liquidity available for drilling and place us at a competitive disadvantage. An increase in interest rates on borrowings under our Senior Secured Credit Facility would result in increased annual interest expense and a decrease in our income before income taxes. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Interest rate risk" for additional information regarding interest rate risk. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and borrowing base.

Borrowings under our Senior Secured Credit Facility expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our Senior Secured Credit Facility. The terms of our Senior Secured Credit Facility provide for interest on borrowings at a floating rate equal to an adjusted base rate tied to U.S. dollar ("USD") London Interbank Offered Rate ("LIBOR"). USD LIBOR tends to fluctuate based on multiple factors, including general short-term interest rates, rates set by the U.S. Federal Reserve, which indicated plans for multiple interest rate increases in 2022, and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. From time to time, we use interest rate swaps to reduce interest rate exposure with respect to our fixed and/or floating rate debt. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

On July 27, 2017, the U.K. Financial Conduct Authority (the "FCA"), the authority that regulates LIBOR, announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. On March 5, 2021, the ICE Benchmark Administration, which administers LIBOR, and the FCA announced that all LIBOR settings will either cease to be provided by any administrator, or no longer be representative immediately after 2021, for all non-USD LIBOR settings and one-week and two-month USD LIBOR settings, and immediately after June 30, 2023 for the remaining USD LIBOR settings. In light of these recent announcements, the future of USD LIBOR at this time is uncertain and any changes in the methods by which USD LIBOR is determined or regulatory activity related to USD LIBOR's phase-out could cause USD LIBOR to perform differently than in the past or cease to exist. Our current credit agreement provides for any changes away from USD LIBOR to a successor rate to be based on prevailing or equivalent standards, however, changes in the method of calculating USD LIBOR, or the discontinuation, reform, or replacement of LIBOR or any other benchmark rates may adversely affect interest rates and result in higher borrowing costs. This could materially and adversely affect our results of operations, cash flow and liquidity.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure that we will generate sufficient cash flows from operations or that future funding will be available to us under our Senior Secured Credit Facility, equity offerings or other actions in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Any significant reduction in our borrowing base under our Senior Secured Credit Facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Senior Secured Credit Facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Senior Secured Credit Facility is currently subject to a borrowing base which is subject to scheduled semiannual (May 1 and November 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Senior Secured Credit Facility. The lenders under our Senior Secured Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Senior Secured Credit Facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in oil, NGL and natural gas reserves engineering;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or

- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

We anticipate borrowing under our Senior Secured Credit Facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Senior Secured Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results. In addition, we keep cash at certain banks that are not FDIC insured or such deposits that exceed the FDIC insured amount. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources" for additional information regarding our liquidity. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and borrowing base.

We have incurred losses from operations for various periods since our inception and may do so in the future.

We incurred net losses in certain years of operation since our inception. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil, NGL and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting estimates."

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our Senior Secured Credit Facility and the indentures governing our senior unsecured notes each contain, and any future indebtedness we incur may contain, various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends on, repurchase or make distributions in respect of our capital stock or make other restricted payments;
- make certain investments;
- sell certain assets;
- create liens;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets; and
- enter into certain transactions with our affiliates.

As a result of these covenants and a covenant in our Senior Secured Credit Facility that limits our ability to hedge, we are limited in the manner in which we may conduct our business, and we may be unable to engage in favorable business activities or finance future operations or our capital needs. In addition, the covenants in our Senior Secured Credit Facility require us to maintain a minimum current ratio and maximum leverage ratio and also limit our capital expenditures. A breach of any of these covenants could result in a default under one or more of these agreements, including as a result of cross-default provisions and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. Upon the occurrence of an event of default under our Senior Secured Credit Facility, the lenders could elect to declare all amounts outstanding under our Senior Secured Credit Facility to be immediately due and payable and terminate all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the senior unsecured notes. If we were unable to repay those amounts, the lenders under our Senior Secured Credit Facility could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under our Senior Secured Credit Facility. If the lenders under our Senior Secured Credit Facility accelerate the repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter. Our Senior Secured Credit Facility matures on July 16, 2025 (subject to a springing maturity date of July 29, 2024 if any of the January 2025 Notes are outstanding on such date).

Risks related to regulation of our business

If we are unable to drill new allocation wells, it could have a material adverse impact on our future production results.

In the State of Texas, allocation wells allow an oil and gas producer to drill a horizontal well under two or more leaseholds that are not pooled. We are active in drilling and producing allocation wells. If regulations regarding allocation wells are made, the RRC denies or significantly delays the permitting of allocation wells or if legislation is enacted that negatively impacts the current process under which allocation wells are permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production, rates of return and other projected capital efficiencies.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business.

Hydraulic fracturing is a practice that is used to stimulate production of oil and/or natural gas from tight formations. The process, which involves the injection of water, proppants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, federal, state and local jurisdictions have adopted, or are considering adopting, regulations that could further restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. See "Item 1. Business—Regulation of the oil and natural gas industry—Hydraulic fracturing" for a further description of federal and state regulations addressing hydraulic fracturing. Additionally, there are certain governmental reviews either under way or being proposed that focus on environmental aspects of hydraulic fracturing practices, which could spur initiatives to further regulate hydraulic fracturing. Additional levels of regulation and permits required through the adoption of new laws and regulations at the federal, state or local level could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation or regulations governing hydraulic fracturing or water disposal wells are enacted into law.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Texas has previously experienced, and may experience again, low inflows of water. As a result of these conditions, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGL and natural gas, which could have an adverse effect on our results of operations, cash flows and financial condition.

Additionally, our operational and production procedures produce large volumes of water that we must properly dispose. The Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (the "EPA") or the state. Furthermore, the State of Texas maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

Because of the necessity to safely dispose of water produced during operational and production activities, these regulations, or others like them, could have a material adverse effect on our future business, financial condition, operating results and prospects. See "Item 1. Business—Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

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

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing-related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In an effort to control induced seismic activity and recent increase in earthquakes in the Permian Basin, which have been linked by the U.S. and local seismologist to wastewater disposal in oil fields, in September 2021, the RRC curtailed the amount of produced water companies were permitted to inject into some wells in the Permian Basin, and has since indefinitely suspended some permits there and expanded the restrictions to other areas.

Because we dispose of large volumes of produced water gathered from our drilling and production operations, these restrictions on the use of produced water and a moratorium on new produced water wells, together with the adoption and implementation of any new laws or regulations, could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or pump it through the pipeline network or other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, which may require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling activity in the affected parts of the Permian Basin less economical and adversely impact our business, financial condition and results of operations. See "Item 1. Business—Regulation of the oil and natural gas industry—Hydraulic fracturing" for a further description of local regulations addressing seismic activity.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC"). We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and, therefore, are exempt from the FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, NGL and natural gas we produce, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

See "Item 1. Business—Regulation of the oil and natural gas industry—“Greenhouse gas" emissions" for a further discussion of the laws and regulations related to greenhouse gases. Extreme weather conditions can interfere with our production and increase our costs, and damage resulting from extreme weather may not be fully insured.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development, marketing, transportation and production activities. These laws and regulations may require us to obtain and maintain a variety of permits, approvals, certificates or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed, and, in some instances, the issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, accidental spills or releases from our operations could expose us to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil, NGL and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental actions are taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

See "Item 1. Business—Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

Designation as “critical infrastructure” could subject us to additional regulation, including potential weatherization requirements.

In response to Winter Storm Uri, the February 2021 winter weather event that caused widespread power failure to Texas’ power grid for several days, the Texas legislature drafted new legislation designed to prepare for, prevent and respond to weather emergencies and power outages. On November 30, 2021, the RRC adopted rules to designate certain natural gas facilities as critical infrastructure. While the Commission did not adopt rules related to other sections of the legislation requiring such designees to implement weatherization measures, it is expected that the Commission will initiate a rulemaking at a later date for such purposes.

Under the new rules, “critical gas suppliers” include, but are not limited to, gas wells, oil leases that produce gas, natural gas pipeline facilities, underground natural gas storage facilities and saltwater disposal facilities. “Critical customers,” which are a subset of critical gas suppliers, are facilities that require electricity to operate. The rules allow for certain facilities to apply for an exception to critical designation, but exclude certain types of highly critical facilities from eligibility for such exception.

If we are designated as a “critical gas supplier” or “critical customer,” we would become subject to additional regulation and compliance costs, including potential future operating and capital costs required to weatherize our assets.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act, the Adopted Derivatives Rules, and the U.S. Resolution Stay Rules could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. We have stopped entering into new hedging transactions with Foreign Counterparties and do not currently intend to resume hedging with Foreign Counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act, the Adopted Derivatives Rules, the U.S. Resolution Stay Rules, and Foreign 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. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations. See "Item 1. Business—Regulation of derivatives" for a further description of the laws and regulations that affect us.

Tax laws and regulations may change over time, and any such changes could adversely affect our business and financial condition.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

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

Oil, NGL and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate, such as the dunes sagebrush lizard could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Risks related to our common stock

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the ability of our stockholders to call special meetings;
- a separate vote of 75% of the voting power of the outstanding shares of capital stock in order for stockholders to amend the bylaws in certain circumstances;
- our board of directors is divided into three classes with each class serving staggered three-year terms;
- stockholders do not have the right to take any action by written consent; and
- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Provisions such as these are also not favored by various institutional investor services, which may periodically "grade" us on various factors, including stockholder rights and corporate governance policies. Certain institutional investors may have internal policies that prohibit investments in companies receiving a certain grade level from such services, and if we fail to meet such criteria, it could limit the number or type of certain investors which might otherwise be attracted to an investment in the Company, potentially negatively impacting the public float and/or market price of our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

Because we have no plans to pay and are currently restricted from paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our Senior Secured Credit Facility and the indentures governing our senior unsecured notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The information required by Item 2. is contained in "Item 1. Business".

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty as of the date hereof, we do not currently believe that any such legal proceedings will have a material adverse effect on our business, financial position, results of operations or liquidity. See Note 15.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of legal proceedings.

Item 4. Mine Safety Disclosures

The operation of our Howard County, Texas sand mine is subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). MSHA may inspect our Howard County mine and may issue citations and orders when it believes a violation has occurred under the Mine Act. While we contract the mining operations of the Howard County mine to an independent contractor, we may be considered an "operator" for purposes of the Mine Act and may be issued notices or citations if MSHA believes that we are responsible for violations.

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

Part II

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

Market for Registrant's Common Equity

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI." On February 23, 2022, the last sale price of our common stock, as reported on the NYSE, was $73.73 per share.

Holders

As of February 22, 2022, there were 114 holders of record of our common stock.

Dividends

We have not paid any cash dividends since our inception. Covenants contained in our Senior Secured Credit Facility and the indentures governing our senior unsecured notes restrict the payment of cash dividends on our common stock. See "Item 1A. Risk Factors—Risks related to our financing and indebtedness—Our debt agreements contain restrictions that limit our flexibility in operating our business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt."

Issuer Purchases of Equity Securities

The following table summarizes purchases of common stock by Laredo:

Period	Total number of shares purchased(1)	Weighted-average price paid per share(1)	Total number of shares purchased as part of publicly announced program	Maximum value that may yet be purchased under the program as of the respective period-end date
October 1, 2021 - October 31, 2021	—	$ —	—	$ —
November 1, 2021 - November 30, 2021	93	$ 72.07	—	$ —
December 1, 2021 - December 31, 2021	—	$ —	—	$ —
Total	93			

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock awards.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

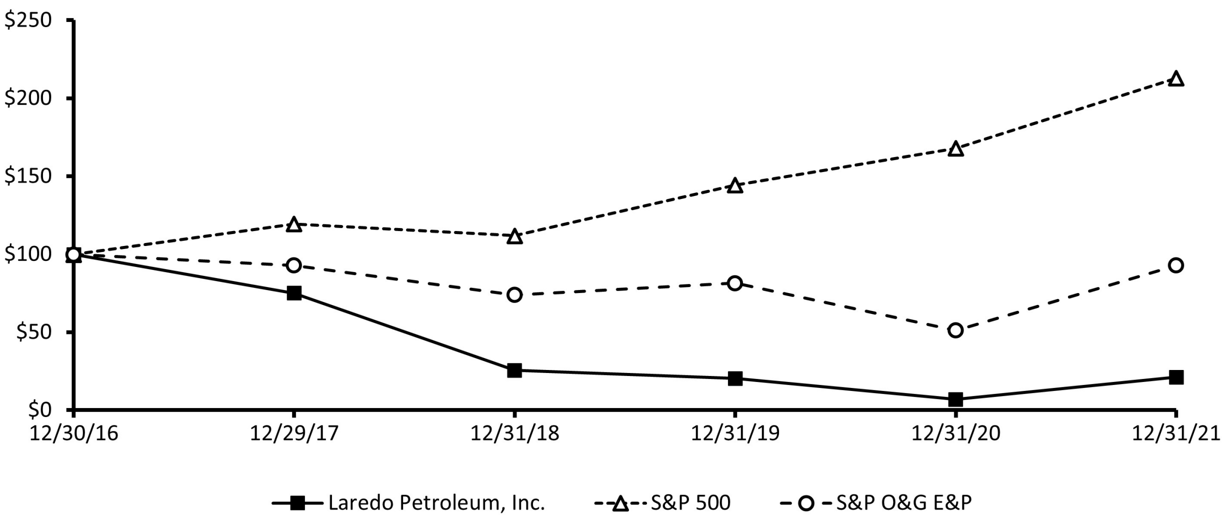
Stock Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below compares the cumulative five-year total returns to our common stockholders relative to the cumulative total returns on the Standard and Poor's 500 Index (the "S&P 500") and the Standard and Poor's Oil & Gas Exploration & Production Select Industry Index (the "S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 31, 2016 to December 31, 2021; and

2. Dividends, if any, are reinvested.



Item 6. [Reserved]

Not applicable.

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 is for the year ended December 31, 2021 compared to 2020, and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Annual Report. Additionally, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2020 Annual Report on Form 10-K for discussion and analysis of our financial condition and results of operations for the year ended December 31, 2020 compared to 2019. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Please see "Cautionary Statement Regarding Forward-Looking Statements" and "Part I, Item 1A. Risk Factors." Unless otherwise specified, references to "average sales price" refer to average sales price excluding the effects of our derivative transactions.

Executive overview

We are an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. Since our inception, we have grown primarily through our drilling program coupled with select strategic acquisitions and joint ventures.

Our financial and operating performance included the following for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change (#)	Change (%)
Oil sales volumes (MBbl)	11,619	9,827	1,792	18 %
Oil equivalents sales volumes (MBOE)	29,827	32,117	(2,290)	(7)%
Oil, NGL and natural gas sales(1)	$ 1,147,143	$ 496,355	$ 650,788	131 %
Net income (loss)(2)	$ 145,008	$ (874,173)	$ 1,019,181	117 %
Free Cash Flow (a non-GAAP financial measure)(3)	$ (2,829)	$ 12,056	$ (14,885)	(123)%
Adjusted EBITDA (a non-GAAP financial measure)(3)	$ 505,917	$ 506,924	$ (1,007)	— %
Proved developed and undeveloped reserves (MBOE)(4)	318,640	278,228	40,412	15 %

(1) Our oil, NGL and natural gas sales increased as a result of a 149% increase in average sales price per BOE and were partially offset by a 7% decrease in total volumes sold.

(2) Our net loss for the year ended December 31, 2020 includes non-cash full cost ceiling impairments totaling $889.5 million.

(3) See pages 64-66 for discussion and calculations of these non-GAAP financial measures.

(4) See Note 19.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of changes in our estimated proved reserve quantities of oil, NGL and natural gas.

Recent developments

2021 Acquisitions and divestiture

On October 18, 2021, we closed the Pioneer Acquisition, and issued 959,691 shares of our common stock constituting a portion of the purchase price. See Note 4.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of the Pioneer Acquisition.

On July 1, 2021, we closed the Sabalo/Shad Acquisition, and issued 2,506,964 shares of our common stock constituting a portion of the purchase price. On July 1, 2021, we also closed the Working Interest Sale. See Note 4.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of the Sabalo/Shad Acquisition and Working Interest Sale.

July 2029 Notes

On July 16, 2021, we closed a private offering and sale of $400.0 million in aggregate principal amount of 7.750% senior unsecured notes due 2029. We received net proceeds from the offering of approximately $392.0 million (after deducting underwriting discounts and commissions and estimated offering expenses), which were used for general corporate purposes, including, repaying a portion of the borrowings outstanding under our Senior Secured Credit Facility.

Senior Secured Credit Facility

On January 14, 2022, we borrowed an additional $50.0 million and on January 31, 2022, we repaid $10.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $145.0 million as of February 21, 2022. See Notes 7.d and 18.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of the Senior Secured Credit Facility.

COVID-19

Although much of the demand for oil and natural gas lost during COVID-19 has recovered, we are not able to predict the duration or ultimate impact that the pandemic will have on our business, financial condition and results of operations. We continue to closely monitor local infection rates and to conform to guidelines and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization and other governmental and regulatory authorities as we have implemented appropriate return-to-work policies while minimizing interruptions to our operations. To date, these measures have not had a material effect on our workforce productivity.

Pricing and reserves

We maintain an active, multi-year commodity derivatives strategy to minimize commodity price volatility and support cash flows needed for operations. We are currently operating three drilling rigs and two completions crews. We expect to release one drilling rig and one completions crew by the end of first-quarter 2022 and maintain two drilling rigs and one completions crew for the remainder of 2022. Our planned capital expenditures for 2022 are expected to be approximately $520.0 million. However, we will continue to monitor commodity prices and service costs and adjust activity levels in order to proactively manage our cash flows and preserve liquidity.

Our results of operations are heavily influenced by oil, NGL and natural gas prices. Historically, commodity prices have experienced significant fluctuations; however, the volatility in the prices has substantially increased in recent years. Another collapse in commodity prices may affect the economic viability of, and our ability to fund our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves. See "Critical accounting estimates" for further discussion of our oil, NGL and natural gas reserve quantities and standardized measure of discounted future net cash flows.

We have entered into a number of commodity derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by fluctuations in price and basis differentials for our sales of oil, NGL and natural gas, as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." See Notes 10.a, 11.a and 18.b to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our commodity derivatives, including transactions subsequent to December 31, 2021.

Our reserves are reported in three streams: oil, NGL and natural gas. The Realized Prices utilized to value our proved reserves as of December 31, 2021 and 2020, are as follows:

	December 31, 2021	December 31, 2020
Realized Prices:		
Oil ($/Bbl)	$ 66.37	$ 37.69
NGL ($/Bbl)	$ 22.90	$ 7.43
Natural gas ($/Mcf)	$ 2.61	$ 0.79

The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling for each of the quarterly periods in 2020 and, as such, we recorded non-cash full cost ceiling impairments totaling $889.5 million during the year ended December 31, 2020. No such full cost ceiling impairments were recorded during the year ended December 31, 2021. Additionally, if prices remain at current levels we do not anticipate recording any full cost ceiling impairments for the foreseeable future. See Notes 2.g and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of the full cost method of accounting and our Realized Prices.

Results of operations

Revenues

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas, the sale of purchased oil and providing midstream services to third parties, all within the continental U.S. and do not include the effects of derivatives. See Note 2.n to our consolidated financial statements included elsewhere in this Annual Report below for additional information regarding our revenue recognition policies.

The following table presents our sources of revenue as a percentage of total revenues for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
	2021	2020	Change (#)	Change (%)
Oil sales	58 %	55 %	3 %	5 %
NGL sales	14 %	12 %	2 %	17 %
Natural gas sales	11 %	7 %	4 %	57 %
Midstream service revenues	— %	1 %	(1)%	(100)%
Sales of purchased oil	17 %	25 %	(8)%	(32)%
Total	100 %	100 %		

Oil, NGL and natural gas sales volumes, revenues and prices

The following table presents information regarding our oil, NGL and natural gas sales volumes, sales revenues and average sales prices for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
	2021	2020	Change (#)	Change (%)
Sales volumes:				
Oil (MBbl)	11,619	9,827	1,792	18 %
NGL (MBbl)	8,678	10,615	(1,937)	(18)%
Natural gas (MMcf)	57,175	70,049	(12,874)	(18)%
Oil equivalents (MBOE)(1)(2)	29,827	32,117	(2,290)	(7)%
Average daily oil equivalent sales volumes (BOE/D)(2)	81,717	87,750	(6,033)	(7)%
Average daily oil sales volumes (Bbl/D)(2)	31,833	26,849	4,984	19 %
Sales revenues (in thousands):				
Oil	$ 805,448	$ 367,792	$ 437,656	119 %
NGL	191,591	78,246	113,345	145 %
Natural gas	150,104	50,317	99,787	198 %
Total oil, NGL and natural gas sales revenues	$ 1,147,143	$ 496,355	$ 650,788	131 %
Average sales prices(2):				
Oil ($/Bbl)(3)	$ 69.32	$ 37.43	$ 31.89	85 %
NGL ($/Bbl)(3)	$ 22.08	$ 7.37	$ 14.71	200 %
Natural gas ($/Mcf)(3)	$ 2.63	$ 0.72	$ 1.91	265 %
Average sales price ($/BOE)(3)	$ 38.46	$ 15.45	$ 23.01	149 %
Oil, with commodity derivatives ($/Bbl)(4)	$ 52.09	$ 56.41	$ (4.32)	(8)%
NGL, with commodity derivatives ($/Bbl)(4)	$ 10.55	$ 9.12	$ 1.43	16 %
Natural gas, with commodity derivatives ($/Mcf)(4)	$ 1.56	$ 1.02	$ 0.54	53 %
Average sales price, with commodity derivatives ($/BOE)(4)	$ 26.36	$ 22.50	$ 3.86	17 %

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented in the years ended December 31, 2021 and 2020 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above or the table below.

(3) Price reflects the average of actual sales prices received when control passes to the purchaser/customer adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point.

(4) Price reflects the after-effects of our commodity derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured commodity derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to commodity derivatives that settled during the respective periods.

The following table presents net settlements (paid) received for matured commodity derivatives and net premiums paid previously or upon settlement attributable to commodity derivatives that matured during the periods utilized in our calculation of the average sales prices, with commodity derivatives, for the periods presented and corresponding changes for such periods:

(in thousands)	Years ended December 31, 2021	Years ended December 31, 2020	2021 compared to 2020 Change ($)	2021 compared to 2020 Change (%)
Net settlements (paid) received for matured commodity derivatives:				
Oil	$ (158,612)	$ 188,594	$ (347,206)	(184)%
NGL	(100,029)	18,553	(118,582)	(639)%
Natural gas	(60,810)	21,147	(81,957)	(388)%
Total	$ (319,451)	$ 228,294	$ (547,745)	(240)%
Net premiums paid previously or upon settlement attributable to commodity derivatives that matured during the respective period:				
Oil	$ (41,553)	$ (2,087)	$ (39,466)	(1,891)%

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2021 and 2020:

(in thousands)	Oil	NGL	Natural gas	Total
2020 Revenues	$ 367,792	$ 78,246	$ 50,317	$ 496,355
Effect of changes in average sales prices	370,564	127,621	109,034	607,219
Effect of changes in sales volumes	67,092	(14,276)	(9,247)	43,569
2021 Revenues	$ 805,448	$ 191,591	$ 150,104	$ 1,147,143
Change ($)	$ 437,656	$ 113,345	$ 99,787	$ 650,788
Change (%)	119 %	145 %	198 %	131 %

The following table presents midstream service revenues and sales of purchased oil for the periods presented and corresponding changes for such periods:

(in thousands)	Years ended December 31, 2021	Years ended December 31, 2020	2021 compared to 2020 Change ($)	2021 compared to 2020 Change (%)
Midstream service revenues	$ 6,629	$ 8,249	$ (1,620)	(20)%
Sales of purchased oil	$ 240,303	$ 172,588	$ 67,715	39 %

Midstream service revenues

Our midstream service revenues decreased for the year ended December 31, 2021 compared to 2020. Midstream service revenues are generated by oil throughput fees and services provided to third parties for (i) integrated oil and natural gas gathering and transportation systems and related facilities, (ii) natural gas lift, fuel for drilling and completions activities and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure and are recognized over time as the customer benefits from these services when provided. These revenues fluctuate and will vary due to oil throughput fees and the level of services provided to third parties. Due to the Working Interest Sale, we anticipate these revenues to continue to decrease in the future.

Sales of purchased oil

Sales of purchased oil are a function of the volumes and prices of purchased oil sold to customers and are offset by the volumes and costs of purchased oil. We are a firm shipper on both the Bridgetex and Gray Oak pipelines and we utilize purchased oil to fulfill portions of our commitments. The continuance of this practice in the future is based upon, among other factors, our pipeline capacity as a firm shipper and the quantity of our lease production which may contribute to our pipeline commitments. Sales of purchased oil increased during the year ended December 31, 2021 compared to 2020 primarily due to an increase in sales prices for purchased oil sold, partially offset by a decrease in volumes of purchased oil sold.

We enter into purchase transactions with third parties and separate sale transactions. These transactions are presented on a gross basis as we act as the principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser/customer at the delivery point based on the price received. The transportation costs associated with these transactions are presented as a component of costs of purchased oil. See "—Costs and expenses - Costs of purchased oil."

Costs and expenses

Costs and expenses and average costs and expenses per BOE sold

The following table presents information regarding costs and expenses and selected average costs and expenses per BOE sold for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands except for per BOE sold data)	**2021**	**2020**	**Change ($)**	**Change (%)**
Costs and expenses:				
Lease operating expenses	$ 101,994	$ 82,020	$ 19,974	24 %
Production and ad valorem taxes	68,742	33,050	35,692	108 %
Transportation and marketing expenses	47,916	49,927	(2,011)	(4)%
Midstream service expenses	3,707	3,762	(55)	(1)%
Costs of purchased oil	251,061	194,862	56,199	29 %
General and administrative (excluding LTIP)	45,906	41,538	4,368	11 %
General and administrative (LTIP):				
LTIP cash	10,299	1,802	8,497	472 %
LTIP non-cash	6,596	7,194	(598)	(8)%
Organizational restructuring expenses	9,800	4,200	5,600	133 %
Depletion, depreciation and amortization	215,355	217,101	(1,746)	(1)%
Impairment expense	1,613	899,039	(897,426)	(100)%
Other operating expenses	4,233	4,430	(197)	(4)%
Total costs and expenses	$ 767,222	$ 1,538,925	$ (771,703)	(50)%
Selected average costs and expenses per BOE sold[(1)]:				
Lease operating expenses	$ 3.42	$ 2.55	$ 0.87	34 %
Production and ad valorem taxes	2.30	1.03	1.27	123 %
Transportation and marketing expenses	1.61	1.55	0.06	4 %
Midstream service expenses	0.12	0.12	—	— %
General and administrative (excluding LTIP)	1.54	1.29	0.25	19 %
Total selected operating expenses	$ 8.99	$ 6.54	$ 2.45	37 %
General and administrative (LTIP):				
LTIP cash	$ 0.35	$ 0.06	$ 0.29	483 %
LTIP non-cash	$ 0.22	$ 0.22	$ —	— %
Depletion, depreciation and amortization	$ 7.22	$ 6.76	$ 0.46	7 %

(1) Selected average costs and expenses per BOE sold are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

Lease operating expenses ("LOE")

LOE, which includes workover expenses, increased for the year ended December 31, 2021 compared to 2020. LOE are daily expenses incurred to bring oil, NGL and natural gas out of the ground and to market, together with the daily expenses incurred to maintain our producing properties. Such costs also include maintenance, repairs and non-routine workover expenses related to our oil and natural gas properties. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to LOE and decreasing failures and related workover expenses. LOE has increased during 2021 due to inflationary pressures and higher operating costs on Howard County wells compared to operating costs on our Eastern (Legacy) acreage, along with increased costs associated with additional wells acquired in the Sabalo/Shad Acquisition and Pioneer Acquisition.

Production and ad valorem taxes

Production and ad valorem taxes increased for the year ended December 31, 2021 compared to 2020 due to increased oil, NGL and natural gas sales revenues. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues, and are established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. Ad valorem taxes are based on and fluctuate in proportion to the taxable value assessed by the various counties where our oil and natural gas properties are located.

Transportation and marketing expenses

Transportation and marketing expenses remained relatively flat for the year ended December 31, 2021 compared to 2020. These are expenses incurred for the delivery of produced oil to customers in the U.S. Gulf Coast market via the Bridgetex pipeline and the Gray Oak pipeline. We ship the majority of our produced oil to the U.S. Gulf Coast, which we believe provides a long-term pricing advantages versus the Midland market. Additionally, firm transportation payments on excess pipeline capacity associated with transportation agreements are included in transportation and marketing expenses. See Note 15.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our transportation commitments.

Midstream service expenses

Midstream service expenses remained flat for the year ended December 31, 2021 compared to 2020. These are expenses incurred to operate and maintain our (i) integrated oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, fuel for drilling and completions activities and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities.

Costs of purchased oil

Costs of purchased oil increased for the year ended December 31, 2021 compared to 2020 primarily due to increased contracted prices of purchased oil on pipelines, partially offset by a decrease in volumes of purchased oil. We are a firm shipper on both the Bridgetex and Gray Oak pipelines and we utilize purchased oil to fulfill portions of our commitments. In the event our long-haul transportation capacity on the Bridgetex pipeline and Gray Oak pipeline is expected to exceed our net production, consistent with our historic practice, we expect to continue to purchase third-party oil at the trading hubs to satisfy the deficit in our associated long-haul transportation commitments.

General and administrative ("G&A")

G&A are expenses incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, non-production based franchise taxes, audit and other fees for professional services, legal compliance and equity-based compensation.

G&A, excluding employee compensation expense from our long-term incentive plan ("LTIP"), increased for the year ended December 31, 2021 compared to 2020 mainly due to an increase in expense for bonuses that will be paid in 2022 as a result of our favorable performance during 2021.

LTIP cash expense increased for the year ended December 31, 2021 compared to 2020. In 2020, we began utilizing cash awards for the majority of our employees rather than equity awards. During the year ended December 31, 2021, we granted new performance unit awards and phantom unit awards. Additionally, the value of our previously granted performance unit awards and phantom unit awards increased significantly during the year ended December 31, 2021 compared to 2020, mainly due to the performance of our stock.

LTIP non-cash expense decreased for the year ended December 31, 2021 compared to 2020. The decrease in LTIP non-cash expense for the year ended December 31, 2021 was due to equity award forfeitures related to the second-quarter 2021 workforce reduction, which were still being expensed in 2020, and was partially offset by a smaller population of 2021 equity awards granted. We currently expect the awards granted in 2022 to be equity awards. See Notes 2.p, 9.a and 17 to our consolidated financial statements included elsewhere in this Annual Report for information regarding our equity-based compensation.

Organizational restructuring expenses

Organizational restructuring expenses are related to our workforce reductions in an effort to reduce costs and better position ourselves for the future in response to market conditions. We incurred charges comprised of compensation, taxes, professional fees, outplacement and insurance-related expenses during the years ended December 31, 2021 and 2020. As of December 31, 2021, no additional organizational restructuring expenses are expected to be incurred. See Note 17 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the organizational restructurings.

Depletion, depreciation and amortization ("DD&A")

The following table presents the components of our DD&A for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Depletion of evaluated oil and natural gas properties	$ 201,691	$ 203,492	$ (1,801)	(1)%
Depreciation of midstream service assets	9,514	9,838	(324)	(3)%
Depreciation and amortization of other fixed assets	4,150	3,771	379	10 %
Total DD&A	$ 215,355	$ 217,101	$ (1,746)	(1)%
Depletion expense per BOE sold	$ 6.76	$ 6.34	$ 0.42	7 %

DD&A decreased slightly for the year ended December 31, 2021 compared to 2020. Depletion expense per BOE increased for the year ended December 31, 2021 compared to 2020 primarily due to the increased future development costs and volumes of our proved reserves as a result of the Sabalo/Shad Acquisition and Pioneer Acquisition and improvements in commodity prices, but was partially offset by the full cost impairments incurred during 2020.

See Notes 2.g and 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the full cost method of accounting.

Impairment expense

The following table presents the components of our impairment expense for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Full cost ceiling impairment expense	$ —	$ 889,453	$ (889,453)	(100)%
Midstream service asset impairment expense	—	8,183	(8,183)	(100)%
Line-fill and other inventories impairment expense	1,613	1,403	210	15 %
Total impairment expense	$ 1,613	$ 899,039	$ (897,426)	(100)%

The unamortized cost of evaluated oil and natural gas properties being depleted did not exceed the full cost ceiling during any of the quarterly periods in 2021. During each of the quarterly periods in 2020, the unamortized costs of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling and, as such, we recorded non-cash full cost ceiling impairments totaling $889.5 million during the year ended December 31, 2020. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report and see "—Pricing and reserves" for additional discussion of full cost ceiling impairments.

Impairments are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method. See Notes 2.i and 11.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our inventory and long-lived assets.

Gain on sale of oil and natural gas properties, net

During the year ended December 31, 2021, we recorded a gain in connection with the Working Interest Sale pursuant to the rules governing full cost accounting, as the divestment represented more than 25% of our June 30, 2021 proved reserves. See Note 4.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the gain on sale of our oil and natural gas properties.

Non-operating income (expense)

The following table presents the components of non-operating income (expense), net for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	**2021**	**2020**	**Change ($)**	**Change (%)**
Gain (loss) on derivatives, net	$ (452,175)	$ 80,114	$ (532,289)	(664)%
Interest expense	(113,385)	(105,009)	(8,376)	(8)%
Gain on extinguishment of debt, net	—	8,989	(8,989)	100 %
Loss on disposal of assets, net	(8,931)	(963)	(7,968)	(827)%
Write-off of debt issuance costs	—	(1,103)	1,103	100 %
Other income, net	2,809	1,586	1,223	77 %
Total non-operating income (expense), net	$ (571,682)	$ (16,386)	$ (555,296)	3,389 %

Gain (loss) on derivatives, net

The following table presents the components of gain on derivatives, net for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	**2021**	**2020**	**Change ($)**	**Change (%)**
Non-cash loss on derivatives, net	$ (140,348)	$ (103,377)	$ (36,971)	36 %
Settlements (paid) received for matured derivatives, net	(320,868)	228,221	(549,089)	(241)%
Settlements received for early-terminated commodity derivatives, net	—	6,340	(6,340)	(100)%
Premiums received (paid) for commodity derivatives	9,041	(51,070)	60,111	118 %
Gain (loss) on derivatives, net	$ (452,175)	$ 80,114	$ (532,289)	(664)%

Non-cash gain (loss) on derivatives, net is the result of (i) new, matured and early-terminated contracts, including contingent consideration derivatives for the period subsequent to the initial valuation date and through the end of the contingency period, and the changing relationship between our outstanding contract prices and the future market prices in the forward curves, which we use to calculate the fair value of our derivatives and (ii) new and matured interest rate swaps and the changing relationship between the contract interest rate and the LIBOR interest rate forward curve. In general, if outstanding commodity contracts are held constant, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices.

Settlements paid or received for matured derivatives are for our (i) commodity derivatives, which are based on the settlement prices compared to the prices specified in the derivative contracts, (ii) interest rate derivative and (iii) contingent consideration derivatives.

During the year ended December 31, 2021, in connection with the Working Interest Sale, we entered into derivative positions on behalf of Sixth Street. Following the closing of the Working Interest Sale on July 1, 2021, all of the hedges entered into on behalf of Sixth Street were novated to Sixth Street as intended.

During the year ended December 31, 2021, we completed a hedge restructuring by (i) selling 2,254,500 calendar year 2021 $55.00 per barrel Brent ICE puts, which volumetrically offset existing calendar year 2021 $55.00 per barrel Brent ICE puts, and receiving aggregate premiums of $9.0 million at inception of the contracts and (ii) entering into 2,254,500 calendar year 2021 Brent ICE swaps at a weighted-average price of $55.09 per barrel. Associated with the aforementioned existing calendar year 2021 $55.00 per barrel Brent ICE puts, which were entered into during 2020, are $50.6 million in aggregate premiums paid at the inception of the contracts.

During the year ended December 31, 2020, we completed hedge restructurings by (i) early terminating collars and entering into new swaps and (ii) early terminating swaps. Additionally, we entered into 2021 puts during the year ended December 31, 2020 and paid $50.6 million in premiums to increase the put price received.

We classify these gains and losses as operating activities in our consolidated statements of cash flows. See Notes 2.e, 4, 10 11.a and 18.b to our consolidated financial statements included elsewhere in this Annual Report and see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below for additional information regarding our derivatives.

Interest expense

Interest expense increased for the year ended December 31, 2021 compared to 2020. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Senior Secured Credit Facility and our senior unsecured notes. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders and bondholders in interest expense, net of amounts capitalized. In addition, we include the amortization of: (i) debt issuance costs (including origination, amendment and professional fees), (ii) deferred premiums associated with our commodity derivative contracts, (iii) commitment fees and (iv) annual agency fees in interest expense. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and interest expense.

Gain on extinguishment of debt, net

During the year ended December 31, 2020, we recognized a (i) loss on extinguishment of debt of $13.3 million related to the difference between the consideration for tender offers, early tender premiums and redemption prices and the net carrying amounts of the extinguished January 2022 Notes and March 2023 Notes and (ii) a gain on extinguishment of debt of $22.3 million related to the difference between the consideration paid and the net carrying amounts of the extinguished portions of the January 2025 Notes and January 2028 Notes. There were no comparable extinguishments of debt during the year ended December 31, 2021. See Notes 7.b and 7.c to our consolidated financial statements included elsewhere in this Annual Report for additional information of our extinguishments of debt.

Loss on disposal of assets, net

Loss on disposal of assets, net, increased for the year ended December 31, 2021 compared to 2020. From time to time, we dispose of inventory, midstream service assets and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price. During the year ended December 31, 2021, the Company retired $18.8 million in midstream service assets, resulting in the removal of $9.4 million in accumulated depreciation and the recognition of an associated loss of $9.4 million.

Write-off of debt issuance costs

We wrote off $1.1 million of debt issuance costs during the years ended December 31, 2020 as a result of decreases in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility. There were no debt issuance costs written off during the year ended December 31, 2021.

Debt issuance costs, which are stated at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. Write-offs of such costs can occur when borrowing terms decrease on our Senior Secured Credit Facility. Write-offs related to our senior unsecured notes occur when the notes have been extinguished and are included in "Gain on extinguishment of debt, net". See Note 7.e to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt issuance costs.

Other income, net

This represents the interest received on our cash and cash equivalents and sublease income as well as other miscellaneous income. See Note 5.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our sublease income.

Income tax (expense) benefit

The following table presents income tax (expense) benefit for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Current	$ (1,324)	$ —	$ (1,324)	(100)%
Deferred	$ (2,321)	$ 3,946	$ (6,267)	(159)%

We are subject to federal and Oklahoma corporate income taxes and the Texas franchise tax. The deferred income tax (expense) benefit for the periods presented is attributed to Texas franchise tax. As of December 31, 2021, we determined it was more likely than not that our federal and Oklahoma net deferred tax assets were not realizable through future net income. As of December 31, 2021, a total valuation allowance of $443.4 million has been recorded to offset our federal and Oklahoma net deferred tax assets, resulting in a Texas net deferred tax liability of $0.8 million. The effective tax rate was not meaningful for the periods presented and we expect it to remain under 1%, due to the full valuation allowance against the Company's federal and Oklahoma net deferred tax assets. In connection with the closing of the Working Interest Sale during the year ended December 31, 2021, and the resulting estimated taxable gain, the Company has recorded a corresponding current tax expense of $1.3 million for Texas franchise tax.

Issuances, sales and/or exchanges of our common stock, taken together with prior transactions with respect to our common stock, could trigger an ownership change and therefore a limitation on our ability to utilize our net operating loss carryforwards which could result in taxable income in future years. For additional discussion of our income taxes, see Note 13 to our consolidated financial statements included elsewhere in this Annual Report and "Critical accounting estimates."

Liquidity and capital resources

Historically, our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties and infrastructure development. While we cannot predict the duration and negative impact of COVID-19 and OPEC+ actions on the energy industry, we believe our cash flows from operations, the net effect of our hedges and the availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund our expected capital expenditures. In 2022, we currently expect to utilize excess cash generated from operations to pay down debt.

We continually monitor the markets and consider which financing alternatives, including debt and equity capital resources, joint ventures and asset sales, are available to meet our future planned capital expenditures, a significant portion of which we are able to adjust and manage. We also continually evaluate opportunities with respect to our capital structure, including issuances of new securities, as well as transactions involving our outstanding senior notes, which could take the form of open market or private repurchases, exchange or tender offers, or other similar transactions, and our common stock, which could take the form of open market or private repurchases. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, or combination of alternatives, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. We continuously look for other opportunities to maximize shareholder value. For further discussion of our financing activities related to debt instruments, see Notes 7 and 18.a to our consolidated financial statements included elsewhere in this Annual Report.

Due to the inherent volatility in the prices of oil, NGL and natural gas and the sometimes wide pricing differentials between where we produce and sell such commodities, we engage in commodity derivative transactions to hedge price risk associated with a portion of our anticipated sales volumes. Due to the inherent volatility in interest rates, we have entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of our anticipated outstanding debt under the Senior Secured Credit Facility. We will pay a fixed rate over the contract term for such portion. By removing a portion of the (i) price volatility associated with future sales volumes and (ii) interest rate volatility associated with anticipated outstanding debt, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below. See Notes 10.a, 10.b and 18.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our (i) commodity derivatives and a summary of open commodity derivative positions as of December 31, 2021 for commodity derivatives that were entered into through December 31, 2021, (ii) interest rate derivative and (iii) subsequent commodity derivative activity and a summary of our resulting open oil derivative positions as of December 31, 2021 for derivative transactions through February 24, 2022, respectively.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2021, we had cash and cash equivalents of $56.8 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $575.9 million, resulting in total liquidity of $632.7 million. As of February 21, 2022, we had cash and cash equivalents of $12.0 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $535.9 million, resulting in total liquidity of $547.9 million. We believe that our operating cash flows and the aforementioned liquidity sources provide us with the financial resources to manage our business needs, implement our currently planned capital expenditure budget and, at our discretion, fund any share repurchases, pay down, repurchase or refinance debt or adjust our planned capital expenditure budget.

The following table presents significant cash requirements for known contractual and other obligations as of December 31, 2021:

(in thousands)	Short-term[1]	Long-term	Total
Senior unsecured notes[2]	$ 123,749	$ 1,894,268	$ 2,018,017
Senior Secured Credit Facility[3]	—	105,000	105,000
Asset retirement obligations[4]	2,946	69,057	72,003
Performance unit award cash payout[5]	—	17,574	17,574
Lease commitments[6]	8,399	6,790	15,189
Total	$ 135,094	$ 2,092,689	$ 2,227,783

(1) We expect to satisfy our short-term contractual and other obligations with cash flows from operations.

(2) Amounts presented include both our principal and interest obligations. The July 2029 Notes consist of $400.0 million principal and interest payments totaling $31.0 million each year with interest payments due semi-annually on January 31 and July 31 of each year until July 31, 2029, commencing January 31, 2022 with interest from closing to such date. The January 2025 Notes and January 2028 Notes consist of $577.9 million and $361.0 million in principal, respectively, and interest payments totaling $54.9 million and $36.6 million each year, respectively, with interest payments due semi-annually on January 15 and July 15 of each year until January 15, 2025 and January 15, 2028.

(3) The $105.0 million principal on our Senior Secured Credit facility is due on July 16, 2025. Amounts presented do not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, amounts presented do not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. See Notes 7.d and 18.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our Senior Secured Credit Facility.

(4) Asset retirement obligations represent future costs associated with the retirement of tangible long-lived assets. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

(5) Amounts represent the estimated cash payout as of December 31, 2021 for our performance unit awards granted on March 5, 2020 and March 9, 2021, utilizing our December 31, 2021 closing stock price. See Note 9.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our performance unit awards.

(6) Lease commitment amounts represent our minimum lease payments for our operating lease liabilities. We have committed to drilling rig contracts with third parties to facilitate our drilling plans. Amounts presented include the gross amount we are committed to pay for the drilling rig contract. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. Management does not currently anticipate the early termination of these contracts in 2022. See Notes 5 and 15.b to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our leases and drilling rig contracts, respectively.

Cash flows

The following table presents our cash flows for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Net cash provided by operating activities	$ 496,671	$ 383,390	$ 113,281	30 %
Net cash used in investing activities	(796,811)	(389,238)	(407,573)	(105)%
Net cash provided by financing activities	308,181	13,748	294,433	2,142 %
Net increase in cash and cash equivalents	$ 8,041	$ 7,900	$ 141	2 %

Cash flows from operating activities

Net cash provided by operating activities increased during the year ended December 31, 2021, compared to 2020. Notable cash changes include (i) an increase in total oil, NGL and natural gas sales revenues of $650.8 million, (ii) a decrease of $495.3 million due to changes in net settlements received for matured and early-terminated derivatives, net of premiums paid, mainly due to increases in commodity prices and (iii) an increase of $25.5 million due to net changes in operating assets and liabilities. Other significant changes include an increase in costs of purchased oil, partially offset by sales of purchased oil and transportation and marketing expenses. The increase in total oil, NGL and natural gas sales revenues is due to a 149% increase in average sales price per BOE and was partially offset by a 7% decrease in total volumes sold. See "—Results of operations" for additional discussion of our oil, NGL and natural gas sales revenues, derivatives and expenses.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the volatility of oil, NGL and natural gas prices, mitigated to the extent of our commodity derivatives' exposure, and sales volume levels. Regional and worldwide economic activity, weather, infrastructure, transportation capacity to reach markets, costs of operations, legislation and regulations, including potential government production curtailments, and other variable factors significantly impact the prices of these commodities. Commodity prices during the periods presented have been most impacted by the effects of COVID-19 on demand and the effects of the OPEC+ actions on supply. These factors are not within our control and are difficult to predict. For additional information on risks related to our business, see "Part I. Item 1A. Risk Factors" and "Part I. Item 7a. Quantitative and Qualitative Disclosures About Market Risk" included elsewhere in this Annual Report.

Cash flows from investing activities

Net cash used in investing activities increased during the year ended December 31, 2021, compared to 2020, mainly due to (i) capital expenditures for the Sabalo/Shad Acquisition and Pioneer Acquisition, (ii) an increase in the number of wells completed and turned-in-line, (iii) an increase in inflationary pressures and non-operated capital expenditures for oil and natural gas properties, all of which was partially offset by proceeds from the Working Interest Sale. See Note 4 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our acquisitions and divestiture of oil and natural gas properties.

The following table presents the components of our cash flows from investing activities for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Acquisitions of oil and natural gas properties, net	$ (763,411)	$ (35,786)	$ (727,625)	(2,033)%
Capital expenditures:				
Oil and natural gas properties	(418,362)	(347,359)	(71,003)	(20)%
Midstream service assets	(2,849)	(3,171)	322	10 %
Other fixed assets	(5,931)	(4,259)	(1,672)	(39)%
Proceeds from dispositions of capital assets, net of selling costs	393,742	1,337	392,405	29,350 %
Net cash used in investing activities	$ (796,811)	$ (389,238)	$ (407,573)	(105)%

Expected capital expenditures

We currently expect capital expenditures for 2022 to be approximately $520.0 million. We are prepared to adjust our capital expenditures further if oil, NGL and natural gas prices continue to exhibit volatility. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The following table presents the components of our incurred capital expenditures, excluding non-budgeted acquisition costs, for the periods presented and corresponding changes for such periods:

	Years ended December 31,		2021 compared to 2020	
(in thousands)	2021	2020	Change ($)	Change (%)
Oil and natural gas properties[1]	$ 444,337	$ 344,160	$ 100,177	29 %
Midstream service assets	2,842	2,985	(143)	(5)%
Other fixed assets	6,807	4,148	2,659	64 %
Total incurred capital expenditures, excluding non-budgeted acquisition costs	$ 453,986	$ 351,293	$ 102,693	29 %

(1) See Note 19.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our incurred capital expenditures in the exploration and development of oil and natural gas properties.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil, NGL and natural gas prices are below our acceptable levels, or costs are above our acceptable levels, we may choose to defer a portion of our capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. Subject to financing alternatives, we may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We continually monitor and may adjust our projected capital expenditures in response to world developments, such as those we experienced in 2020, as well as success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs and supplies, changes in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash flows from financing activities

Net cash provided by financing activities increased during the year ended December 31, 2021, compared to 2020. Notable 2021 activity includes borrowings on our Senior Secured Credit Facility, proceeds from the issuance of our July 2029 Notes and proceeds from our "at-the-market" equity program (the "ATM Program"), partially offset by payments on our Senior Secured Credit Facility. For further discussion of our financing activities related to debt instruments, see Notes 7 and 18.a to our consolidated financial statements included elsewhere in this Annual Report. For further discussion of our financing activities related to stockholders' equity, see Note 8.a to our consolidated financial statements included elsewhere in this Annual Report.

The following table presents the components of our cash flows from financing activities for the periods presented and corresponding changes for such periods:

(in thousands)	Years ended December 31, 2021	2020	2021 compared to 2020 Change ($)	Change (%)
Borrowings on Senior Secured Credit Facility	$ 570,000	$ 80,000	$ 490,000	613 %
Payments on Senior Secured Credit Facility	(720,000)	(200,000)	(520,000)	(260)%
Issuance of January 2025 Notes and January 2028 Notes	—	1,000,000	(1,000,000)	(100)%
Issuance of July 2029 Notes	400,000	—	400,000	100 %
Extinguishment of debt	—	(846,994)	846,994	100 %
Proceeds from issuance of common stock, net of offering costs	72,492	—	72,492	100 %
Stock exchanged for tax withholding	(2,596)	(779)	(1,817)	(233)%
Payments for debt issuance costs	(14,686)	(18,479)	3,793	21 %
Other	2,971	—	2,971	100 %
Net cash provided by financing activities	$ 308,181	$ 13,748	$ 294,433	2,142 %

Sources of liquidity

We are the borrower under our Senior Secured Credit Facility and a party to the indentures governing our senior unsecured notes.

Senior Secured Credit Facility

As of December 31, 2021, our Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") had a maximum credit amount of $2.0 billion and an aggregate elected commitment of $725.0 million, with $105.0 million outstanding and was subject to an interest rate of 2.625%. The Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2021 and 2020, we had one letter of credit outstanding of $44.1 million, under the Senior Secured Credit Facility.

Per the decision of the Financial Conduct Authority, two-month U.S. dollar LIBOR ceased to be published or available on December 31, 2021. Our Senior Secured Credit Facility provides a mechanism for replacing such rate for a two-month period; we have not and do not intend to borrow for two-month interest periods.

See Notes 7.d and 18.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

January 2025 Notes, January 2028 Notes and July 2029 Notes

The following table presents principal amounts and applicable interest rates for our outstanding January 2025 Notes, January 2028 Notes and July 2029 Notes as of December 31, 2021:

(in millions, except for interest rates)	Principal	Interest rate
January 2025 Notes	$ 577.9	9.500 %
January 2028 Notes	361.0	10.125 %
July 2029 Notes	400.0	7.750 %
Total senior unsecured notes	$ 1,338.9	

The net proceeds from the January 2025 Notes and January 2028 Notes were used to fund the tender offers and redemptions of the remaining principal amounts of the January 2022 Notes and March 2023 Notes. Under our bond repurchase program, we repurchased a portion of our January 2025 Notes and 2028 Notes during the year ended December 31, 2020. On July 16, 2021, we closed a private offering and sale of $400.0 million in aggregate principal amount of our 7.750% senior unsecured notes due 2029. See Notes 7.d and 18.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our senior unsecured notes.

ATM Program

On February 23, 2021, we entered into an equity distribution agreement with Wells Fargo Securities, LLC acting as sales agent and/or principal (the "Sales Agent"), pursuant to which we may offer and sell, from time to time through the Sales Agent, shares of our common stock having an aggregate gross sales price of up to $75.0 million through the ATM Program.

During the year ended December 31, 2021, we sold 1,438,105 shares of our common stock pursuant to the ATM Program for net proceeds of approximately $72.5 million, after underwriting commissions and other related expenses, completing the ATM Program. Proceeds from the share sales were utilized to reduce borrowings on our Senior Secured Credit Facility.

Supplemental Guarantor information

As discussed in Note 7 to our consolidated financial statements included elsewhere in this Annual Report, on January 24, 2020, we issued $600.0 million in aggregate principal amount of the January 2025 Notes and $400.0 million in aggregate principal amount of the January 2028 Notes. On July 16, 2021, we issued $400.0 million in aggregate principal amount of the July 2029 Notes. As of December 31, 2021, $1.3 billion of our senior unsecured notes remained outstanding. Each of our wholly owned subsidiaries, LMS and GCM (each, a "Guarantor," and together, the "Guarantors"), jointly and severally, and fully and unconditionally, guarantees the January 2025 Notes, January 2028 Notes and July 2029 Notes. We do not have any non-guarantor subsidiaries.

The guarantees are senior unsecured obligations of each Guarantor and rank equally in right of payment with other existing and future senior indebtedness of such Guarantor, and senior in right of payment to all existing and future subordinated indebtedness of such Guarantor. The guarantees of the senior unsecured notes by the Guarantors are subject to certain Releases. The obligations of each Guarantor under its note guarantee are limited as necessary to prevent such note guarantee from constituting a fraudulent conveyance under applicable law. Further, the rights of holders of the senior unsecured notes against the Guarantors may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Laredo is not restricted from making investments in the Guarantors and the Guarantors are not restricted from making intercompany distributions to Laredo or each other.

As we do not have any non-guarantor subsidiaries, the assets, liabilities and results of operations of the combined issuer and Guarantors are not materially different than the corresponding amounts presented in our consolidated financial statements included elsewhere in this Annual Report. Accordingly, we have omitted the summarized financial information of the issuer and the Guarantors that would otherwise be required.

Non-GAAP financial measures

The non-GAAP financial measures of Free Cash Flow and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP financial measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flows from operating activities. Free Cash Flow and Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Free Cash Flow

Free Cash Flow is a non-GAAP financial measure that we define as net cash provided by operating activities (GAAP) before changes in operating assets and liabilities, net, less incurred capital expenditures, excluding non-budgeted acquisition costs. Free Cash Flow does not represent funds available for future discretionary use because it excludes funds required for future debt service, capital expenditures, acquisitions, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating operating trends in our business that are affected by production, commodity prices, operating costs and other related factors.

There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to Free Cash Flow (non-GAAP) for the periods presented:

	Years ended December 31	
(in thousands)	**2021**	**2020**
Net cash provided by operating activities	$ 496,671	$ 383,390
Less:		
Change in current assets and liabilities, net	49,321	36,699
Change in noncurrent assets and liabilities, net	(3,807)	(16,658)
Cash flows from operating activities before changes in operating assets and liabilities, net	451,157	363,349
Less incurred capital expenditures, excluding non-budgeted acquisition costs:		
Oil and natural gas properties[(1)]	444,337	344,160
Midstream service assets[(1)]	2,842	2,985
Other fixed assets	6,807	4,148
Total incurred capital expenditures, excluding non-budgeted acquisition costs	453,986	351,293
Free Cash Flow (non-GAAP)	$ (2,829)	$ 12,056

(1) Includes capitalized share-settled equity-based compensation and asset retirement costs.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss (GAAP) plus adjustments for share-settled equity-based compensation, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid or received for commodity derivatives that matured during the period, accretion expense, gains or losses on disposal of assets, interest expense, income taxes and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for future discretionary use because it excludes funds required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items that can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss and the lack of comparability of results of operations to different companies due to the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP) for the periods presented:

	Years ended December 31,	
(in thousands, unaudited)	**2021**	**2020**
Net income (loss)	$ 145,008	$ (874,173)
Plus:		
Share-settled equity-based compensation, net	7,675	8,217
Depletion, depreciation and amortization	215,355	217,101
Impairment expense	1,613	899,039
Gain on sale of oil and natural gas properties, net	(93,482)	—
Organizational restructuring expenses	9,800	4,200
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	452,175	(80,114)
Settlements (paid) received for matured derivatives, net	(320,868)	228,221
Settlements received for early-terminated commodity derivatives, net	—	6,340
Net premiums paid for commodity derivatives that matured during the period[1]	(41,553)	(477)
Accretion expense	4,233	4,430
Loss on disposal of assets, net	8,931	963
Interest expense	113,385	105,009
Gain on extinguishment of debt, net	—	(8,989)
Write-off of debt issuance costs	—	1,103
Income tax expense (benefit)	3,645	(3,946)
Adjusted EBITDA (non-GAAP)	$ 505,917	$ 506,924

(1) Reflects net premiums paid previously or upon settlement that are attributable to derivatives settled in the respective periods presented.

Critical accounting estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements.

In management's opinion, the most critical accounting estimates impacted by our judgments and estimates are (i) volumes of our reserves of oil, NGL and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) deferred income taxes, (iv) asset retirement obligations and (v) fair values of assets acquired and liabilities assumed in an acquisition.

There have been no material changes in our accounting estimates during the year ended December 31, 2021. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report for discussion on significant accounting policies and estimates made by management.

Oil, NGL and natural gas reserve quantities and standardized measure of discounted future net cash flows

On an annual basis, our independent reserve engineers prepare the estimates of oil, NGL and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant judgment in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective assumptions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material. See Notes 19.d and 19.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our net proved oil, NGL and natural gas reserves and standardized measure of discounted future net cash flows, respectively.

Income taxes

As of December 31, 2021 and 2020, we had a net deferred tax liability of $0.8 million and a net deferred tax asset of $1.5 million, respectively.

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items such as derivative instruments, depletion, depreciation and amortization, and certain accrued assets and liabilities for tax and financial accounting purposes. These differences and our net operating loss carry-forwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheets. We must then assess, using all available negative and positive evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for all or a portion of the deferred tax asset. Among the more significant types of evidence that we consider are:

- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;
- the ability to recover our net operating loss carry-forward deferred tax assets in future years;
- the existence of significant proved oil, NGL and natural gas reserves;
- our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;
- current price protection utilizing commodity hedges;
- future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- current market prices for oil, NGL and natural gas.

During 2021, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered all positive and negative evidence available and determined it was more likely than not that the net deferred tax assets were not realizable and a valuation allowance was necessary. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Asset retirement obligations ("ARO")

We have significant obligations to (i) plug, abandon and remediate the properties at the end of their productive lives and (ii) remove certain midstream service assets and remediate the sites where such midstream service assets are located upon the retirement of those assets. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on our experience and estimated remaining life per well, (ii) estimated removal and/or remediation costs for midstream service assets and estimated remaining life of midstream service assets, (iii) future inflation factors and (iv) our average credit-adjusted risk-free rate. Inherent in the fair value calculation of ARO are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in technology, regulatory, political, environmental, safety and public relations matters. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, an adjustment will be made to the asset balance. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our ARO.

Acquisitions

As part of our business strategy, we actively pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties, which are measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net cash flows of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. Changes in key assumptions may cause the accounting for acquisitions to be revised, including the recognition of additional goodwill or discount on acquisition. See Note 4.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our 2021 acquisitions.

New accounting standards

There are no new accounting standards not yet adopted and meaningful to disclose as of December 31, 2021. Additionally, we did not adopt any new accounting standards during the year ended December 31, 2021.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2021, 2020 and 2019. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and we are experiencing inflationary pressures on the costs of oilfield services and equipment.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk," in our case, refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices and in interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk-sensitive derivative instruments were entered into for hedging purposes, rather than for speculative trading.

Oil, NGL and natural gas price exposure

Due to the inherent volatility in oil, NGL and natural gas prices and the sometimes wide pricing differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of our anticipated sales volumes. By removing a portion of the price volatility associated with future sales volumes, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

The fair values of our open commodity derivative positions are largely determined by the relevant forward commodity price curves of the indexes associated with our open derivative positions. We had a $178.3 million net liability position from the fair values of our open commodity derivatives as of December 31, 2021. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 10% change in the relevant forward commodity price curves of the indexes associated with our open commodity derivative positions as of December 31, 2021:

(in thousands)	10% Increase	10% Decrease
Commodity	$ (91,633)	$ 92,059

See Notes 2.e, 10.a, 10.c, 11.a and 18.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our commodity and contingent consideration derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our notes bear interest at fixed rates. The maturity years, outstanding balances and interest rates on our long-term debt as of December 31, 2021 were as follows:

	Maturity year		
(in millions except for interest rates)	2023	2025	Thereafter
January 2025 Notes	$ —	$ 577.9	$ —
Fixed interest rate	— %	9.500 %	— %
January 2028 Notes	$ —	$ —	$ 361.0
Fixed interest rate	— %	— %	10.125 %
July 2029 Notes	$ —	$ —	$ 400.0
Fixed interest rate	— %	— %	7.750 %
Senior Secured Credit Facility	$ 105.0	$ —	$ —
Floating interest rate	2.625 %	— %	— %

Due to the inherent volatility in interest rates, we have entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of our anticipated outstanding debt under the Senior Secured Credit Facility. We will pay a fixed rate over the contract term for that portion. By removing a portion of the interest rate volatility associated with anticipated outstanding debt, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

The fair value of our open interest rate derivative position is largely determined by the LIBOR interest rate forward curve associated with our open position. We had a $0.1 million total liability position from the net fair value of our open interest rate derivative as of December 31, 2021. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 1% incremental addition to or subtraction from the relevant LIBOR forward curve interest rates associated with our open interest rate derivative position as of December 31, 2021:

(in thousands)	1% incremental addition to	1% incremental subtraction from
Interest rate	$ 328	$ (328)

See Notes 7, 11.c and 18.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our debt. See Notes 10.b and 11.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our interest rate derivative.

Counterparty and customer credit risk

See Notes 14 and 15 to our consolidated financial statements included elsewhere in this Annual Report for discussion of credit risk and commitments and contingencies. See Notes 2.d and 2.n to our consolidated financial statements included elsewhere in this Annual Report for discussion of our accounts receivable and revenue recognition, respectively. See Notes 2.e, 10.a, 11.a and 18.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our commodity derivatives.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2021, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2021.

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.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on internal control over financial reporting

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2021, and our report dated February 24, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 24, 2022

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

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2021 at the reasonable assurance level.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and operating effectiveness of our internal controls over financial reporting as part of this Annual Report for the year ended December 31, 2021. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. Other Information

Not applicable.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer, principal financial officer and principal accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2021.

Item 11. Executive Compensation

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2021.

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

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2021.

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

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2021.

Item 14. Principal Accounting Fees and Services

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2021.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 Financial Statements and Supplementary Data" in this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit	Description	Incorporated by reference (File No. 001-35380, unless otherwise indicated)		
		Form	Exhibit	Filling Date
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc., dated as of December 19, 2011.	8-K	2.1	12/22/2011
2.2^	Purchase and Sale Agreement, dated May 7, 2021, by and among Laredo Petroleum, Inc., Sabalo Energy, LLC and Sabalo Operating, LLC.	8-K	2.1	5/11/2021
2.3^	Purchase and Sale Agreement, dated May 7, 2021, by and between Laredo Petroleum, Inc. and Shad Permian, LLC.	8-K	2.2	5/11/2021
2.4^	Purchase and Sale Agreement, dated May 7, 2021, by and between Laredo Petroleum, Inc. and Piper Investments Holdings, LLC.	8-K	2.3	5/11/2021
2.5^	Purchase and Sale Agreement, dated September 17, 2021, by and among Laredo Petroleum, Inc., Pioneer Natural Resources USA, Inc., DE Midland III LLC, Parsley Minerals, LLC, and Parsley Energy, L.P.	8-K	2.1	9/20/2021
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc., dated as of December 19, 2011.	8-K	3.1	12/22/2011
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc., dated as of June 1, 2020.	8-K	3.1	6/1/2020
3.3	Certificate of Ownership and Merger, dated as of December 30, 2013.	8-K	3.1	1/6/2014
3.4	Third Amended and Restated Bylaws of Laredo Petroleum, Inc., adopted March 3, 2021.	8-K	3.1	3/4/2021
4.1	Form of Common Stock Certificate.	8-A12B/A	4.1	1/7/2014
4.2*	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.			
4.3	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.1	3/24/2015
4.4	Third Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.4	1/24/2020
4.5	Fourth Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.6	1/24/2020
4.6	Indenture, dated as of July 16, 2021, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee.	8-K	4.1	7/16/2021
10.1	Fifth Amended and Restated Credit Agreement, dated as of May 2, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the other financial institutions signatory thereto.	10-Q	10.1	5/4/2017
10.2	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 24, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	10/30/2017
10.3	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of February 14, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	10-K	10.3	2/15/2018
10.4	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	4/23/2018
10.5	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 30, 2020, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	5/6/2020
10.6	Fifth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of October 22, 2020, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	10/22/2020

Exhibit	Description	Incorporated by reference (File No. 001-35380, unless otherwise indicated) Form	Exhibit	Filling Date
10.7	Sixth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of May 7, 2021, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	5/11/2021
10.8	Seventh Amendment to the Fifth Amended and Restated Credit Agreement, dated as of July 16, 2021, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.2	7/16/2021
10.9	Purchase Agreement, dated July 13, 2021, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Securities, LLC, as representative of the several initial purchasers named therein.	8-K	10.1	7/16/2021
10.10	Amended and Restated Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof.	10-Q	10.5	5/2/2019
10.11#	Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 20, 2021.	8-K	10.1	5/20/2021
10.12#	Laredo Petroleum, Inc. Change in Control Executive Severance Plan, as amended June 21, 2015, December 14, 2015 and September 9, 2016.	10-K	10.18	2/16/2017
10.13#	Laredo Petroleum, Inc. Executive Severance Plan, effective as of February 20, 2020.	8-K	10.1	2/26/2020
10.14#	Offer Letter, dated April 17, 2019, between Laredo Petroleum, Inc. and Mr. Jason Pigott.	10-Q	10.3	5/2/2019
10.15#	Offer Letter, dated June 12, 2020, between Laredo Petroleum, Inc. and Mr. Bryan J. Lemmerman.	10-Q	10.3	8/6/2020
10.16#	Form of Stock Option Agreement.	8-K	10.3	5/25/2016
10.17#	Form of 2019 Performance Share Unit Award Agreement.	10-Q	10.4	5/2/2019
10.18#	Form of 2020 Performance Share Unit Award Agreement.	10-K	10.18	2/22/2021
10.19#	Form of 2021 Performance Share Unit Award Agreement.	10-Q	10.3	5/6/2021
10.20#	Form of Outperformance Share Unit Award Agreement.	10-Q	10.8	8/1/2019
10.21#	Form of Restricted Stock Unit Agreement.	8-K	10.2	5/25/2016
10.22#	Form of Phantom Unit Agreement.	10-K	10.21	2/22/2021
21.1	List of Subsidiaries of Laredo Petroleum, Inc.	10-K	21.1	2/22/2021
22.1	List of Issuers and Guarantor Subsidiaries	10-Q	22.1	5/7/2020
23.1*	Consent of Grant Thornton LLP.			
23.2*	Consent of Ryder Scott Company, L.P.			
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.			
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.			
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
95.1*	Mine Safety Disclosures.			
99.1*	Summary Report of Ryder Scott Company, L.P.			
101	The following financial information from Laredo's Annual Report on Form 10-K for the year ended December 31, 2021, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).			

* Filed herewith.

** Furnished herewith.

Management contract or compensatory plan or arrangement.

^ Certain schedules and exhibits to this agreement have been omitted in accordance with Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished to the SEC on request.

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.

	Laredo Petroleum, Inc.	
Date: February 24, 2022	By:	/s/ Jason Pigott
		Jason Pigott *President and Chief Executive Officer*

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Jason Pigott, Bryan J. Lemmerman, T. Karen Chandler, Mark D. Denny and Jessica R. Wren, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signatures	Title	Date
/s/ Jason Pigott Jason Pigott	President and Chief Executive Officer (principal executive officer)	2/24/2022
/s/ Bryan J. Lemmerman Bryan J. Lemmerman	Senior Vice President and Chief Financial Officer (principal financial officer)	2/24/2022
/s/ Jessica R. Wren Jessica R. Wren	Senior Director of Financial Accounting and SEC Reporting (principal accounting officer)	2/24/2022
/s/ William E. Albrecht William E. Albrecht	Chairman	2/24/2022
/s/ Francis Powell Hawes Frances Powell Hawes	Director	2/24/2022
/s/ Jarvis V. Hollingsworth Jarvis V. Hollingsworth	Director	2/24/2022
/s/ Craig M. Jarchow Craig M. Jarchow	Director	2/24/2022
/s/ Lisa M. Lambert Lisa M. Lambert	Director	2/24/2022
/s/ Lori A. Lancaster Lori A. Lancaster	Director	2/24/2022
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/24/2022
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/24/2022

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' 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 February 24, 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 matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 matter below, providing separate opinions on the critical audit matter or on the accounts or disclosures to which they relate.

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

  As described further in Notes 2 and 6 to the financial statements, the Company accounts for its oil and natural 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 to determine if any impairment exists for its oil and natural gas properties. To estimate the volume of proved reserves and future net revenues, 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 impairment expense. We identified the estimation of proved reserves of oil and natural gas properties due to its impact on depletion expense and impairment of oil and natural 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, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company’s proved reserves could have a significant impact on the measurement of depletion expense or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the 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 natural gas properties for potential impairment. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company’s accounting records and the management review controls performed on information provided to the reservoir engineering specialists and the management review controls on the final proved reserves report prepared by the Company’s reservoir engineering specialists.
- We evaluated the level of knowledge, skill, and ability of the Company’s reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers 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 reservoir engineering specialists.
- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other financial inputs and assumptions, including certain assumptions that are derived from the Company’s accounting records. These assumptions included historical pricing differentials, future operating costs, estimated future 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 as follows:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
    - Evaluated the models used to estimate the future operating costs at year-end and compared the models to historical operating costs;
    - Evaluated the models used to estimate future capital expenditures to amounts expended for recently drilled and completed wells;
    - Evaluated the ownership interests used in the reserve report by inspecting lease and title records;
    - 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 to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing the reserve report to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2007.

Tulsa, Oklahoma
February 24, 2022

Consolidated balance sheets

(in thousands, except share data)	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 56,798	$ 48,757
Accounts receivable, net	151,807	63,976
Derivatives	4,346	7,893
Other current assets	22,906	15,964
Total current assets	235,857	136,590
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	8,968,668	7,874,932
Unevaluated properties not being depleted	170,033	70,020
Less: accumulated depletion and impairment	(7,019,670)	(6,817,949)
Oil and natural gas properties, net	2,119,031	1,127,003
Midstream service assets, net	96,528	112,697
Other fixed assets, net	34,590	32,011
Property and equipment, net	2,250,149	1,271,711
Derivatives	32,963	—
Operating lease right-of-use assets	11,514	17,973
Other noncurrent assets, net	21,341	16,336
Total assets	$ 2,551,824	$ 1,442,610
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 71,386	$ 38,279
Accrued capital expenditures	50,585	28,275
Undistributed revenue and royalties	117,920	24,728
Derivatives	179,809	31,826
Operating lease liabilities	7,742	11,721
Other current liabilities	99,471	62,766
Total current liabilities	526,913	197,595
Long-term debt, net	1,425,858	1,179,266
Derivatives	—	12,051
Asset retirement obligations	69,057	64,775
Operating lease liabilities	5,726	8,918
Other noncurrent liabilities	10,490	1,448
Total liabilities	2,038,044	1,464,053
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2021 and 2020	—	—
Common stock, $0.01 par value, 22,500,000 shares authorized and 17,074,516 and 12,020,164 issued and outstanding as of December 31, 2021 and 2020, respectively	171	120
Additional paid-in capital	2,788,628	2,398,464
Accumulated deficit	(2,275,019)	(2,420,027)
Total stockholders' equity	513,780	(21,443)
Total liabilities and stockholders' equity	$ 2,551,824	$ 1,442,610

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

Consolidated statements of operations

(in thousands, except per share data)	Years ended December 31, 2021	2020	2019
Revenues:			
Oil sales	$ 805,448	$ 367,792	$ 572,918
NGL sales	191,591	78,246	100,330
Natural gas sales	150,104	50,317	33,300
Midstream service revenues	6,629	8,249	11,928
Sales of purchased oil	240,303	172,588	118,805
Total revenues	1,394,075	677,192	837,281
Costs and expenses:			
Lease operating expenses	101,994	82,020	90,786
Production and ad valorem taxes	68,742	33,050	40,712
Transportation and marketing expenses	47,916	49,927	25,397
Midstream service expenses	3,707	3,762	4,486
Costs of purchased oil	251,061	194,862	122,638
General and administrative	62,801	50,534	54,729
Organizational restructuring expenses	9,800	4,200	16,371
Depletion, depreciation and amortization	215,355	217,101	265,746
Impairment expense	1,613	899,039	620,889
Other operating expenses	4,233	4,430	4,118
Total costs and expenses	767,222	1,538,925	1,245,872
Gain on sale of oil and natural gas properties, net	93,482	—	—
Operating income (loss)	720,335	(861,733)	(408,591)
Non-operating income (expense):			
Gain (loss) on derivatives, net	(452,175)	80,114	79,151
Interest expense	(113,385)	(105,009)	(61,547)
Litigation settlement	—	—	42,500
Gain on extinguishment of debt, net	—	8,989	—
Loss on disposal of assets, net	(8,931)	(963)	(248)
Write-off of debt issuance costs	—	(1,103)	(935)
Other income, net	2,809	1,586	4,623
Total non-operating income (expense), net	(571,682)	(16,386)	63,544
Income (loss) before income taxes	148,653	(878,119)	(345,047)
Income tax (expense) benefit:			
Current	(1,324)	—	—
Deferred	(2,321)	3,946	2,588
Total income tax (expense) benefit	(3,645)	3,946	2,588
Net income (loss)	$ 145,008	$ (874,173)	$ (342,459)
Net income (loss) per common share:			
Basic	$ 10.18	$ (74.92)	$ (29.61)
Diluted	$ 10.03	$ (74.92)	$ (29.61)
Weighted-average common shares outstanding:			
Basic	14,240	11,668	11,565
Diluted	14,464	11,668	11,565

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

Consolidated statements of stockholders' equity

(in thousands)	Common stock Shares	Common stock Amount	Additional paid-in capital	Treasury stock (at cost) Shares	Treasury stock (at cost) Amount	Accumulated deficit	Total
Balance, December 31, 2018	11,697	$ 2,339	$ 2,375,286	—	$ —	$ (1,203,395)	$ 1,174,230
Restricted stock awards	381	76	(76)	—	—	—	—
Restricted stock forfeitures	(178)	(35)	35	—	—	—	—
Stock exchanged for tax withholding	—	—	—	35	(2,657)	—	(2,657)
Stock exchanged for cost of exercise of stock options	—	—	—	1	(76)	—	(76)
Retirement of treasury stock	(36)	(7)	(2,726)	(36)	2,733	—	—
Exercise of stock options	1	—	76	—	—	—	76
Share-settled equity-based compensation	—	—	12,760	—	—	—	12,760
Net loss	—	—	—	—	—	(342,459)	(342,459)
Balance, December 31, 2019	11,865	2,373	2,385,355	—	—	(1,545,854)	841,874
Reverse stock split	—	(2,277)	2,277	—	—	—	—
Restricted stock awards	238	31	(31)	—	—	—	—
Restricted stock forfeitures	(48)	(2)	2	—	—	—	—
Stock exchanged for tax withholding	—	—	—	35	(779)	—	(779)
Retirement of treasury stock	(35)	(5)	(774)	(35)	779	—	—
Share-settled equity-based compensation	—	—	11,635	—	—	—	11,635
Net loss	—	—	—	—	—	(874,173)	(874,173)
Balance, December 31, 2020	12,020	120	2,398,464	—	—	(2,420,027)	(21,443)
Restricted stock awards	237	2	(2)	—	—	—	—
Restricted stock forfeitures	(42)	—	—	—	—	—	—
Stock exchanged for tax withholding	—	—	—	53	(2,596)	—	(2,596)
Retirement of treasury stock	(53)	—	(2,596)	(53)	2,596	—	—
Exercise of stock options	2	—	173	—	—	—	173
Share-settled equity-based compensation	—	—	9,258	—	—	—	9,258
Issuance of common stock, net of costs	1,438	14	72,478	—	—	—	72,492
Equity issued for acquisitions of oil and natural gas properties	3,467	35	310,853	—	—	—	310,888
Performance share conversion	6	—	—	—	—	—	—
Net income	—	—	—	—	—	145,008	145,008
Balance, December 31, 2021	17,075	$ 171	$ 2,788,628	—	$ —	$ (2,275,019)	$ 513,780

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

Consolidated statements of cash flows

(in thousands)	Years ended December 31, 2021	2020	2019
Cash flows from operating activities:			
Net income (loss)	$ 145,008	$ (874,173)	$ (342,459)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Share-settled equity-based compensation, net	7,675	8,217	8,290
Depletion, depreciation and amortization	215,355	217,101	265,746
Impairment expense	1,613	899,039	620,889
Gain on sale of oil and natural gas properties, net	(93,482)	—	—
Mark-to-market on derivatives:			
(Gain) loss on derivatives, net	452,175	(80,114)	(79,151)
Settlements (paid) received for matured derivatives, net	(320,868)	228,221	63,221
Settlements received (paid) for early-terminated commodity derivatives, net	—	6,340	(5,409)
Premiums received (paid) for commodity derivatives	9,041	(51,070)	(9,063)
Amortization of debt issuance costs	5,146	4,321	3,341
Amortization of operating lease right-of-use assets	13,609	13,070	14,563
Gain on extinguishment of debt, net	—	(8,989)	—
Deferred income tax expense (benefit)	2,321	(3,946)	(2,588)
Other, net	13,564	5,332	3,887
Changes in operating assets and liabilities:			
Accounts receivable, net	(87,831)	21,117	8,924
Other current assets	(8,767)	6,275	(14,059)
Other noncurrent assets, net	(8,782)	(6,768)	2,327
Accounts payable and accrued liabilities	31,387	(2,242)	(28,983)
Undistributed revenue and royalties	81,201	(8,395)	(16,037)
Other current liabilities	33,331	19,944	(13,968)
Other noncurrent liabilities	4,975	(9,890)	(4,397)
Net cash provided by operating activities	496,671	383,390	475,074
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties, net	(763,411)	(35,786)	(199,284)
Capital expenditures:			
Oil and natural gas properties	(418,362)	(347,359)	(458,985)
Midstream service assets	(2,849)	(3,171)	(7,910)
Other fixed assets	(5,931)	(4,259)	(2,433)
Proceeds from dispositions of capital assets, net of selling costs	393,742	1,337	6,901
Net cash used in investing activities	(796,811)	(389,238)	(661,711)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	570,000	80,000	275,000
Payments on Senior Secured Credit Facility	(720,000)	(200,000)	(90,000)
Issuance of January 2025 Notes and January 2028 Notes	—	1,000,000	—
Issuance of July 2029 Notes	400,000	—	—
Extinguishment of debt	—	(846,994)	—
Proceeds from issuance of common stock, net of offering costs	72,492	—	—
Stock exchanged for tax withholding	(2,596)	(779)	(2,657)
Payments for debt issuance costs	(14,686)	(18,479)	—
Other	2,971	—	—
Net cash provided by financing activities	308,181	13,748	182,343
Net increase (decrease) in cash and cash equivalents	8,041	7,900	(4,294)
Cash and cash equivalents, beginning of period	48,757	40,857	45,151
Cash and cash equivalents, end of period	$ 56,798	$ 48,757	$ 40,857

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

Notes to the consolidated financial statements

Note 1 Organization

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. The Company has identified one operating segment: exploration and production. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these consolidated financial statements and the related notes are rounded and, therefore, approximate.

Note 2 Basis of presentation and significant accounting policies

a. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts.

b. Use of estimates in the preparation of consolidated financial statements

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

Significant estimates include, but are not limited to, (i) volumes of the Company's reserves of oil, natural gas liquids ("NGL") and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) depletion, depreciation and amortization, (iv) impairments, (v) asset retirement obligations, (vi) equity-based compensation, (vii) deferred income taxes, (viii) fair values of assets acquired and liabilities assumed in an acquisition, (ix) fair values of derivatives and deferred premiums and (x) contingent assets or liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that would be used by market participants. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets may increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual values and results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

c. Cash and cash equivalents

The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less. The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. See Note 14 for discussion regarding the Company's exposure to credit risk.

d. Accounts receivable

The Company sells its produced oil, NGL and natural gas and purchased oil to various customers and participates with other parties in the development and operation of oil and natural gas properties.

The Company maintains an allowance for expected credit losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers significant factors such as historical losses, current receivables aging, the debtors' current ability to pay its obligation to the Company and existing industry and economic data. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote, and payments subsequently received on such balances are credited to the allowance. See Note 14 for discussion regarding the Company's exposure to credit risk.

Accounts receivable consisted of the following components as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Oil, NGL and natural gas sales[(1)]	$ 135,560	$ 46,714
Joint operations, net[(2)]	11,491	2,753
Sales of purchased oil and other products	4,756	5,083
Derivatives and other	—	9,426
Total accounts receivable, net	$ 151,807	$ 63,976

(1) For purchasers that the Company has netting arrangements with, the amounts presented include the net positions.

(2) Accounts receivable for joint operations are presented net of an allowance for expected credit losses of $0.4 million as of both December 31, 2021 and 2020. As the operator of the majority of its wells, the Company has the ability to realize some or all of these receivables through the netting of revenues.

e. Derivatives

Derivatives are recorded at fair value and are presented on a net basis in "Derivatives" on the consolidated balance sheets as assets and/or liabilities. The Company records the fair value of derivatives, net by counterparty where the right of offset exists. The Company determines the fair value of its derivatives using fair value hierarchy level inputs to its valuation techniques. The Company's derivatives were not designated as hedges for accounting purposes, and the Company does not enter into such instruments for speculative trading purposes. Accordingly, the changes in fair value are recognized in "Gain (loss) on derivatives, net" under "Non-operating income (expense)" on the consolidated statements of operations. See Notes 10 and 11.a for additional discussion of derivatives and their fair value measurement on a recurring basis, respectively.

f. Other current assets and liabilities

Other current assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Prepaid expenses and other	$ 12,746	$ 12,768
Inventory[(1)]	10,160	3,196
Total other current assets	$ 22,906	$ 15,964

(1) See Note 2.i for discussion of the Company's types of inventory.

Other current liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Accrued interest payable	$ 56,468	$ 42,401
Accrued compensation and benefits	14,434	16,687
Other accrued liabilities	28,569	3,678
Total other current liabilities	$ 99,471	$ 62,766

g. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain employee-related costs, incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and, once evaluated, depleted on a composite unit-of-production method based on estimates of proved oil, NGL and natural gas reserves. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Capitalized costs include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including employee-related costs, associated with production and general corporate activities are expensed in the period incurred.

The Company excludes unevaluated property acquisition costs and exploration costs from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties and such costs become subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling incurred capital expenditures to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas. See Note 4.a for discussion of the Company's sale of oil and natural gas properties and the resulting gain recognized during the year ended December 31, 2021. See Note 6 for additional discussion of the Company's oil and natural gas properties and other property and equipment.

h. Leases

The Company recognizes operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheets for operating leases with an initial term greater than 12 months.

The Company determines whether a contract is or contains a lease at inception of the contract, based on answers to a series of questions that address whether an identified asset exists and whether the Company has the right to obtain substantially all of the benefit of the asset and to control its use over the full term of the agreement. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company determines its IBR using both a "credit notching" approach and a "recovery method" approach. The results of these approaches are then weighted equally and averaged in order to determine the concluded IBR. This concluded IBR is utilized to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees, nor any restrictions or covenants included in the Company's lease agreements.

Mineral leases, including oil and natural gas leases granting the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not included in the scope of Accounting Standards Codification ("ASC") 842, *Leases*.

The Company has recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheets for leases of commercial real estate with lease terms extending into 2027 and drilling, completion, production and other equipment leases with lease terms extending into 2022. The Company has various other drilling, completion and production equipment leases on a short-term basis which are reflected in short-term lease costs.

The Company's lease costs include those that are recognized in net income (loss) during the period and capitalized as part of the cost of another asset in accordance with other GAAP.

The lease costs related to drilling, completion and production activities are reflected at the Company's net ownership, which is consistent with the principals of proportional consolidation, and lease commitments are reflected on a gross basis. As of

December 31, 2021, the Company had an average working interest of 96% in wells associated with Laredo's active drilling program over the next 12 months.

Certain of the Company's leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput, actual days or another measure of usage. For our drilling rigs, the variable lease costs include the payments that depend on the performance or usage of the underlying asset, the costs to move and the costs to repair the drilling rigs. For certain of our commercial office buildings, utilities and common area, the variable lease costs are the variable maintenance charges. For our equipment leases, the variable lease costs are the amounts incurred under our contracts that are beyond the minimum rental fee, inclusive of maintenance.

The Company subleases certain office space to third parties but remains the primary obligor under the head lease. The lease terms on those subleases each contain renewal options that do not extend past the term of the head lease. The subleases do not contain residual value guarantees. Sublease income is recognized based on the contract terms and is included as a reduction of lease expense under the head lease.

Certain of the Company's operating lease right-of-use asset classes include options to renew on a month-to-month basis. The Company considers contract-based, asset-based, market-based and entity-based factors to determine the term over which it is reasonably certain to extend the lease in determining its right-of-use assets and liabilities.

The Company's material leases do not include options to purchase the leased property.

See Note 5 for further discussion of the Company's leases.

i. Inventory

The Company has the following types of inventory: (i) materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, (ii) frac pit water inventory used in developing oil and natural gas properties and (iii) line-fill in third-party pipelines, which is the minimum volume of product in a pipeline system that enables the system to operate, and is generally not available to be withdrawn from the pipeline until the expiration of the transportation contract. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method, and is included in "Other current assets" and "Other noncurrent assets, net" on the consolidated balance sheets. The NRV for materials and supplies inventory and frac pit water inventory is estimated utilizing a replacement cost approach (Level 2). The NRV for line-fill in third-party pipelines is estimated utilizing a quoted market price adjusted for regional price differentials (Level 2). See Note 11.b for discussion of the Company's inventory impairments.

j. Debt issuance costs

Debt issuance costs, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the straight-line method. See Note 7.e for additional discussion of the Company's debt issuance costs.

k. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is expensed through depletion, or for midstream service assets through depreciation. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and accretion expense.

The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows into a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment or removal and remediation cost per well or midstream service asset based on Company experience, if any, in accordance with applicable state laws, (ii) estimated remaining life per well or midstream service asset, (iii) future inflation factors and (iv) the Company's average credit-adjusted risk-free rate. Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in technology, regulatory, political, environmental, safety and public relations matters. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, an adjustment will be made to the asset balance.

The Company is obligated by contractual and regulatory requirements to remove certain midstream service assets and perform other remediation of the sites where such midstream service assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. The Company will record an asset retirement obligation for midstream service assets in the periods in which settlement dates are reasonably determinable.

The following table reconciles the Company's asset retirement obligation liability associated with tangible long-lived assets for the periods presented:

	Years ended December 31,	
(in thousands)	2021	2020
Liability at beginning of year	$ 68,326	$ 62,718
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	14,610	2,252
Accretion expense[(1)]	4,233	4,430
Liabilities settled due to plugging and abandonment or removed due to sale	(15,186)	(1,074)
Revision of estimates	20	—
Liability at end of year	$ 72,003	$ 68,326

(1) Accretion expense is included in "Other operating expenses" on the consolidated statements of operations.

l. Fair value measurements

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values. See Note 2.i for the fair value assumptions used in estimating the NRV of inventory, which is used to determine the necessity for any inventory impairment. See Note 4 for the fair value assumptions used in estimating the fair values of assets acquired and liabilities assumed in the Company's acquisitions. See Note 11 for further discussion of fair value measurements.

m. Treasury stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result of (i) stock exchanged to satisfy tax withholding that arises upon the lapse of restrictions on share-settled equity-based awards at the awardee's election or (ii) stock exchanged for the cost of exercise of stock options at the awardee's election.

n. Revenue recognition

Oil, NGL and natural gas sales and sales of purchased oil are generally recognized at the point in time that control of the product is transferred to the customer. Midstream service revenues are recognized over time as the customer benefits from services when provided.

Oil sales and sales of purchased oil

Under its oil sales contracts, the Company sells produced or purchased oil at the delivery point specified in the contract and collects an agreed-upon index price, net of pricing differentials. The delivery point may be at the wellhead, the inlet of the purchaser's pipeline or nominated pipeline or the Company's truck unloading facility. At the delivery point, the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606, *Revenue from Contracts with Customers*, typically passes at the delivery point. The Company recognizes revenue at the net price received when control transfers to the purchaser.

The Company engages in transactions in which it sells oil at the lease and subsequently repurchases the same volume of oil from that customer at a downstream delivery point under a separate agreement ("Repurchase Agreement") for use in the sale to the final customer. The commercial reasoning for such transactions may vary. Where a Repurchase Agreement exists, the Company must evaluate whether the customer obtains control of the oil at the lease and therefore whether it is appropriate to recognize revenue for the lease sale. Where the Company has an obligation or a right to repurchase the oil, the customer does not obtain control of the oil because it is limited in its ability to direct the use of, and obtain substantially all of the remaining benefits from the oil even though it may have physical possession of the oil. If the Company repurchases the oil for less than the original selling price, such a transaction will be classified as a lease. If the Company repurchases the oil for equal to or more than the original selling price, then the transaction represents a financing arrangement unless there is only a short passage of time between the sale and repurchase, in which case any excess amount paid represents an expense associated with the sale of oil to the final customer. The Company recognizes such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expenses" line item in the accompanying consolidated statements of operations.

In certain situations, the Company enters into purchase and sale transactions of oil inventory with the same counterparty in contemplation with one another, and these transactions are presented on the consolidated statements of operations on a net basis in accordance with ASC 845, *Nonmonetary Transactions*. The following table presents the net effect of these transactions for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Sales of purchased oil inventory	$ 327,839	$ 17,026	$ —
Purchased oil inventory	326,625	16,918	—
Net effect on earnings(1)	$ 1,214	$ 108	$ —

(1) Amounts presented are recorded in "Sales of purchased oil" in the consolidated statements of operations.

Under certain of its customer contracts, the Company is subject to contractual penalties if it fails to deliver contractual minimum volumes to its customers. Such amounts are recorded as a reduction to the transaction price as these amounts do not represent payments to the customer for distinct goods or services and instead relate specifically to the failure to perform under the specific customer contract. Such amounts are recorded as a reduction to the transaction price when payment is determined as probable, typically when such a deficiency occurs.

NGL and natural gas sales

Under its natural gas processing contracts, the Company delivers produced natural gas to a midstream processing entity at the wellhead or the inlet of the processing entity's system. The processing entity processes the natural gas, sells the resulting NGL and residue gas to third parties and pays the Company for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For existing contracts, the Company has concluded that it is the agent in the ultimate sale to the third party and the midstream processing entity is the principal and that the Company has transferred control of unprocessed natural gas to the midstream processing entity; therefore, the Company recognizes revenue based on the net amount of the proceeds received from the midstream processing entity who represents the Company's customer. If for future contracts the Company was to conclude that it was the principal with the ultimate third party being the customer, the Company would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream service revenues

Revenue from oil throughput agreements is recognized based on a rate per barrel for volumes transported. Under the Company's oil throughput agreements, a volumetric deduction is taken from customer oil as a pipeline loss allowance. While these amounts represent non-cash consideration under ASC 606, such deductions are immaterial. Revenue from natural gas throughput agreements is recognized based on a rate per MMbtu for volumes transported. Revenue from water delivery, recycling and takeaway is recognized based on the volumes of water for which the services are provided at the applicable contractual rate.

Imbalances

The Company recognizes revenue for all oil, NGL and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil, NGL and natural gas reserves. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of December 31, 2021 or 2020.

Significant judgments

The Company engages in various types of transactions in which unaffiliated midstream entities process the Company's liquids-rich natural gas and, in some scenarios, subsequently market resulting NGL and residue gas to third-party customers on the Company's behalf. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. For existing contracts, the Company has determined that it serves as the agent in the sale of products under certain natural gas processing and marketing agreements with unaffiliated midstream entities in accordance with the control model in ASC 606, *Revenue from Contracts with Customers*. As a result, the Company presents revenue on a net basis for amounts expected to be received from third-party customers through the marketing process, with expenses and deductions incurred subsequent to control of the product(s) transferring to the unaffiliated midstream entity being netted against revenue.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year and for its Midstream Services, the Company has utilized the practical expedient in ASC 606-10-50-14A that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied. Under the Midstream Services contracts each unit of service represents a separate performance obligation and therefore performance obligations in respect of future services are wholly unsatisfied.

Contract balances

Under the Company's customer contracts, invoicing occurs once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606, *Revenue from Contracts with Customers*.

Prior-period performance obligations

For sales of oil, NGL, natural gas and purchased oil, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 30 to 90 days after the date production is delivered and, as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the years ended December 31, 2021, 2020 and 2019, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

o. Fees received for the operation of jointly-owned oil and natural gas properties

The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as a reduction of general and administrative expenses.

The following table presents the fees received for the operation of jointly-owned oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Fees received for the operation of jointly-owned oil and natural gas properties	$ 876	$ 464	$ 468

p. Equity-based compensation awards

Equity-based compensation expense is included in "General and administrative" on the consolidated statements of operations, and includes expense for (i) restricted stock awards, stock option awards, performance share awards and the outperformance share award, which are accounted for as equity awards and are generally based on the awards' grant date or modification date fair value less an expected forfeiture rate and (ii) performance unit awards and phantom unit awards, which are accounted for as liability awards and are re-measured at each quarterly reporting period until settlement. The Company capitalizes a portion of equity-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized equity-based compensation is included in "Evaluated properties" on the consolidated balance sheets. See Note 9.a for further discussion of the Company's Equity Incentive Plan.

q. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carryforwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company has no unrecognized tax benefits related to uncertain tax positions in the consolidated financial statements at December 31, 2021 or 2020. See Note 13 for additional information regarding the Company's income taxes.

r. Supplemental cash flow and non-cash information

The following table presents supplemental cash flow and non-cash information for the periods presented:

(in thousands)	Years ended December 31, 2021	2020	2019
Supplemental cash flow information:			
Cash paid for interest, net of $5,866, $3,019 and $805 of capitalized interest, respectively[(1)]	$ 94,867	$ 77,401	$ 58,216
Net cash received for income taxes[(2)]	$ —	$ 2,129	$ 3,187
Supplemental non-cash investing information:			
Fair value of contingent consideration asset (liability) on transaction closing date[(3)]	$ 33,832	$ (225)	$ (6,150)
Change in accrued capital expenditures	$ 22,310	$ (8,053)	$ 6,353
Capitalized share-settled equity-based compensation	$ 1,583	$ 3,418	$ 4,470
Capitalized asset retirement cost	$ 14,610	$ 2,252	$ 4,755

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(1) See Note 7.f for additional discussion of the Company's interest expense.

(2) See Note 13 for additional discussion of the Company's income taxes.

(3) See Notes 4.a, 4.b and 4.d for additional discussion of the Company's acquisitions and divestiture of oil and natural gas properties that include contingent considerations. See Note 11.a for discussion of the quarterly remeasurement of the respective contingent considerations.

The following table presents supplemental non-cash adjustments information related to operating leases for the periods presented:

(in thousands)	Years ended December 31, 2021	2020
Right-of-use assets obtained in exchange for operating lease liabilities[(1)]	$ 7,742	$ 2,349

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(1) See Note 5 for additional discussion of the Company's leases.

Note 3 New accounting standards

The Company considered the applicability and impact of all accounting standard updates ("ASU") issued by the Financial Accounting Standards Board ("FASB") to the Accounting Standards Codification ("ASC") and has determined there are no ASUs that are not yet adopted and meaningful to disclose as of December 31, 2021. Additionally, the Company did not adopt any new ASUs during the year ended December 31, 2021.

Note 4 Acquisitions and divestitures

a. 2021 Asset acquisitions and divestiture

Pioneer Acquisition

On September 17, 2021, the Company entered into a purchase and sale agreement (the "Pioneer PSA") with Pioneer Natural Resources USA, Inc ("PXD"), DE Midland III, LLC ("DEM"), Parsley Minerals, LLC ("PM") and Parsley Energy, L.P. ("PE" and collectively with PXD, DEM, and PM, "the Seller") pursuant to which the Company agreed to purchase (the "Pioneer Acquisition"), effective as of July 1, 2021, certain oil and natural gas properties in the Midland Basin, including approximately 20,000 net acres, and approximately 135 gross (121 net) operated locations, located in western Glasscock County, Texas, as well as related assets and contracts (the "Pioneer Assets").

On October 18, 2021 ("Pioneer Closing Date"), the Company closed the Pioneer Acquisition for an aggregate purchase price of $205.6 million, comprised of (i) $131.6 million in cash, (ii) 959,691 shares of the Company's common stock, par value $0.01 per share (the "common stock"), based upon the share price as of the Pioneer Closing Date and (iii) $3.0 million in transaction related expenses, inclusive of customary closing adjustments, subject to post-closing adjustments.

The Company determined that the Pioneer Acquisition was an asset acquisition, as substantially all of the gross assets acquired are concentrated in a group of similar identifiable assets. Accordingly, the consideration paid was allocated to the individual assets acquired and liabilities assumed based on their relative fair values and all transaction costs associated were capitalized.

The following table presents components of the purchase price, inclusive of customary closing adjustments:

(in thousands, except for share and share price data)	As of October 18, 2021
Shares of Company common stock	959,691
Company common stock price at the Pioneer Closing Date	$ 73.90
Value of Company common stock consideration	$ 70,921
Cash consideration	$ 131,633
Transaction costs	3,013
Total purchase price	$ 205,567

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on the Pioneer Closing Date:

(in thousands)	As of October 18, 2021
Evaluated properties	$ 139,360
Unevaluated properties	73,929
Revenue suspense liabilities assumed	(7,722)
Allocated purchase price	$ 205,567

The Company funded the cash portion of the aggregate purchase price and related transaction costs with respect to the Pioneer Acquisition with cash on hand and borrowings under its Senior Secured Credit Facility.

During the year ended December 31, 2021, in connection with the Pioneer Acquisition, the Company acquired additional interests in the Pioneer Assets through additional sellers that exercised their "tag-along" sales rights, for total cash consideration of $2.9 million, excluding customary purchase price adjustments. These acquisitions were accounted for as asset acquisitions.

Sabalo/Shad Acquisition

On May 7, 2021, the Company entered into two separate purchase and sale agreements, one (the "Sabalo PSA") with Sabalo Energy, LLC and its subsidiary, Sabalo Operating, LLC (collectively, "Sabalo"), and the other (the "Shad PSA" and together with the Sabalo PSA, the "Sabalo/Shad PSAs") with Shad Permian, LLC ("Shad") to acquire certain Midland Basin oil and natural gas properties, including approximately 21,000 net acres and approximately 120 gross (109 net) operated locations and approximately 150 gross (18 net) non-operated locations, located in Howard and Borden Counties, Texas, (collectively, the "Sabalo/Shad Acquisition"). Sabalo and Shad are unaffiliated, but owned interest in the same assets.

On July 1, 2021 ("Sabalo/Shad Closing Date"), the Company closed the Sabalo/Shad Acquisition, effective April 1, 2021, for an aggregate purchase price of $863.1 million, comprised of (i) $606.1 million in cash (ii) 2,506,964 shares of the Company's common stock, based upon the share price as of the Sabalo/Shad Closing Date, and (iii) $17.0 million in transaction related expenses, inclusive of customary closing adjustments, subject to post-closing adjustments.

The Sabalo/Shad Acquisition was accounted for as a single transaction because the Sabalo PSA and Shad PSA were entered into at the same time and in contemplation of one another to form a single transaction designed to achieve an overall economic effect. The Company determined that the Sabalo/Shad Acquisition was an asset acquisition, as substantially all of the gross assets acquired are concentrated in a group of similar identifiable assets. Accordingly, the consideration paid was allocated to the individual assets acquired and liabilities assumed based on their relative fair values and all transaction costs associated were capitalized.

The following table presents components of the purchase price, inclusive of customary closing adjustments:

(in thousands, except for share and share price data)		As of July 1, 2021
Shares of Company common stock		2,506,964
Company common stock price at the Sabalo/Shad Closing Date	$	95.72
Value of Company common stock consideration	$	239,967
Cash consideration	$	606,126
Transaction costs		17,020
Total purchase price	$	863,113

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on the Sabalo/Shad Closing Date:

(in thousands)		As of July 1, 2021
Evaluated properties	$	503,005
Unevaluated properties		362,977
Revenue suspense liabilities assumed		(4,269)
Inventory		1,400
Allocated purchase price	$	863,113

The Company funded the cash portion of the aggregate purchase price and related transaction costs with respect to the Sabalo/Shad Acquisition with proceeds from borrowings under its Senior Secured Credit Facility (as defined below) and the Working Interest Sale described below.

Working Interest Sale

On May 7, 2021, the Company entered into a purchase and sale agreement (the "Sixth Street PSA") with Piper Investments Holdings, LLC, an affiliate of Sixth Street Partners, LLC ("Sixth Street"), to sell 37.5% of the Company's working interest in certain producing wellbores and the related properties primarily located within Glasscock and Reagan Counties, Texas, subject to certain excluded assets and title diligence procedures (the "Working Interest Sale").

On July 1, 2021 (the "Sixth Street Closing Date") the Company closed the Working Interest Sale for cash proceeds of $405.0 million. In addition to such proceeds, the Sixth Street PSA also provided the Company with the right to receive up to a maximum of $93.7 million in additional cash consideration if certain cash flow targets related to divested oil and natural gas property operations are met ("Sixth Street Contingent Consideration"). The Sixth Street Contingent Consideration is made up of quarterly payments through June 2027 totaling up to $38.7 million and a potential balloon payment of $55.0 million in June 2027. On the Sixth Street Closing Date, the fair value of the Sixth Street Contingent Consideration was determined to be $33.8 million. The Sixth Street Contingent Consideration is accounted for as a contingent consideration derivative, with all gains and losses as a result of changes in the fair value of the contingent consideration derivative recognized in earnings in the period in which the changes occur. See Notes 10.c and 11.a for further discussion of the Sixth Street Contingent Consideration.

Subsequent to the Sixth Street Closing Date, the Company continues to own and operate its remaining working interest in the properties sold to Sixth Street; however, the results of operations and cash flows related to the 37.5% working interests sold were eliminated from the Company's financial statements. This divestiture did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

Pursuant to the rules governing full cost accounting, the Company recorded a gain on the Working Interest Sale of $93.5 million, net of transaction expenses of $11.6 million, on the Company's consolidated statements of operations, subject to post-closing adjustments, as this divestment represented more than 25% of the Company's June 30, 2021 proved reserves.

For the purposes of calculating the gain, total capitalized costs were allocated between reserves sold and reserves retained as of the Sixth Street Closing Date.

Leasehold acquisitions

During the year ended December 31, 2021, the Company acquired certain oil and natural gas leasehold interests in Howard County, Texas, totaling approximately 455 net acres for an aggregate purchase price of $4.0 million.

b. 2020 Asset acquisitions

On October 16, 2020 and November 16, 2020, the Company closed a bolt-on acquisition of 2,758 and 80 net acres, respectively, including production of 210 BOE/D, in Howard County, Texas for an aggregate purchase price of $11.6 million, subject to customary post-closing purchase price adjustments.

On April 30, 2020, the Company closed an acquisition of 180 net acres in Howard County, Texas for $0.6 million. The acquisition also provides for one or more potential contingent payments to be paid by the Company if the arithmetic average of the monthly settlement WTI NYMEX prices exceed certain thresholds for the contingency period beginning on January 1, 2021 and ending on the earlier of December 31, 2022 or the date the counterparty has received the maximum consideration of $1.2 million. The fair value of this contingent consideration was $0.2 million as of the acquisition date, which was recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. See Notes 10.c and 11.a for additional discussion of this contingent consideration.

On February 4, 2020, the Company closed a transaction for $22.5 million, acquiring 1,180 net acres and divesting 80 net acres in Howard County, Texas.

All transaction costs were capitalized and are included in "Oil and natural gas properties, net" on the consolidated balance sheet.

c. 2020 Divestiture

On April 9, 2020, the Company closed a divestiture of 80 net acres and working interests in two producing wells in Glasscock County, Texas for $0.7 million, net of customary post-closing sales price adjustments. The divestiture was recorded as an adjustment to oil and natural gas properties pursuant to the rules governing full cost accounting. Effective at closing, the operations and cash flows of these oil and natural gas properties were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. This divestiture did not represent a strategic shift and has not had a major effect on the Company's future operations or financial results.

d. 2019 Acquisitions

Asset acquisitions

On December 12, 2019, the Company closed an acquisition of 7,360 net acres and 750 net royalty acres in Howard County, Texas for $131.7 million, net of customary closing purchase price adjustments. The acquisition provided for a potential contingent payment, where the Company was required to pay $20 million if the arithmetic average of the monthly settlement WTI NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeded a certain threshold. The fair value of this contingent consideration was $6.2 million as of the acquisition date, which was recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. See Notes 10.c and 11.a for additional discussion of this contingent consideration. This acquisition was primarily financed through borrowings under the Senior Secured Credit Facility. Post-closing was finalized during the year ended December 31, 2020.

On June 20, 2019, the Company acquired 640 net acres in Reagan County, Texas for $2.9 million.

All transaction costs were capitalized and are included in "Oil and natural gas properties, net" on the consolidated balance sheet.

Business combination

On December 6, 2019, the Company closed a bolt-on acquisition of 4,475 contiguous net acres and working interests in 49 producing wells in western Glasscock County, Texas, which included net production of 1,400 BOE/D at the time of acquisition, for $64.6 million, net of customary closing purchase price adjustments. This acquisition was financed through borrowings under the Senior Secured Credit Facility. Post-closing was finalized during the year ended December 31, 2020.

This acquisition was accounted for as a business combination. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisition were expensed. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties. The fair values of these properties were measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net cash flows of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. These assumptions represent Level 3 inputs under the fair value hierarchy, as described in Note 11.

The following table reflects an aggregate of the final estimate of the fair values of the assets acquired and liabilities assumed in this business combination on December 6, 2019:

(in thousands)	Fair values of acquisition
Fair values of net assets:	
Evaluated oil and natural gas properties	$ 29,921
Unevaluated oil and natural gas properties	34,700
Asset retirement cost	2,728
Total assets acquired	$ 67,349
Asset retirement obligations	(2,728)
Net assets acquired	$ 64,621
Fair values of consideration paid for net assets:	
Cash consideration	$ 64,621

e. Exchange of unevaluated oil and natural gas properties

From time to time, the Company exchanges undeveloped acreage with third parties. The exchanges are recorded at fair value and the difference is accounted for as an adjustment of capitalized costs with no gain or loss recognized pursuant to the rules governing full cost accounting, unless such adjustment would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

Note 5 Leases

See Note 2.h for discussion of the Company's significant accounting policies for oil and natural gas properties.

a. Lease costs

The following table presents components of total lease costs, net for the periods presented:

(in thousands)	Years ended December 31, 2021	2020
Operating lease costs[1]	$ 15,894	$ 15,094
Short-term lease costs[2]	83,471	82,576
Variable lease costs[3]	6,873	10,218
Sublease income	(1,057)	(1,032)
Total lease costs, net	$ 105,181	$ 106,856

(1) Amounts represent straight-line costs associated with the Company's operating lease right-of-use assets.

(2) Amounts include costs associated with the Company's short-term leases that are not included in the calculation of lease liabilities and right-of-use assets and, therefore, are not recorded on the consolidated balance sheets as such.

(3) Amounts are primarily comprised of the non-lease service component of drilling rig commitments above the minimum required payments, and are not included in the calculation of lease liabilities and right-of-use assets. Both the minimum required payments and the non-lease service component of the drilling rig commitments are capitalized as additions to oil and natural gas properties.

b. Operating leases

Supplemental cash flow information

The following table presents cash paid for amounts included in the measurement of operating lease liabilities, which may not agree to operating lease costs due to timing of cash payments and incurred capital expenditures for the periods presented:

(in thousands)	Years ended December 31, 2021	2020
Operating cash flows from operating leases	$ 4,065	$ 5,910
Investing cash flows from operating leases[1]	$ 12,569	$ 9,425

(1) Amounts associated with drilling operations are capitalized as additions to oil and natural gas properties.

Lease terms and discount rates

The following table presents the weighted-average remaining lease term and weighted-average discount rate for operating leases as of the dates presented:

	December 31, 2021	December 31, 2020
Weighted-average remaining lease term	2.80 years	2.87 years
Weighted-average discount rate	7.41 %	7.72 %

Maturities

The following table reconciles the undiscounted cash flows for recognized operating lease liabilities for each of the first five years and the total remaining years to the operating lease liabilities recorded on the consolidated balance sheet as of the date presented:

(in thousands)	December 31, 2021
2022	$ 8,399
2023	1,925
2024	1,428
2025	1,423
2026	1,348
Thereafter	666
Total minimum lease payments	15,189
Less: lease liability expense	(1,721)
Present value of future minimum lease payments	13,468
Less: current operating lease liabilities	(7,742)
Noncurrent operating lease liabilities	$ 5,726

Other information

See Note 2.r for disclosure of supplemental non-cash adjustments information related to operating leases.

Note 6 Property and equipment

a. Oil and natural gas properties

See Note 2.g for discussion of the Company's significant accounting policies for oil and natural gas properties.

The following table presents capitalized employee-related incurred capital expenditures in the acquisition, exploration and development of oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Capitalized employee-related costs	$ 18,225	$ 18,954	$ 18,299

See Note 19.a for total incurred capital expenditures in the acquisition, exploration and development of oil and natural gas properties, which includes the aforementioned capitalized employee-related costs.

The following table presents depletion expense, which is included in "Depletion, depreciation and amortization" on the consolidated statements of operations, and depletion expense per BOE sold of evaluated oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands except per BOE data)	2021	2020	2019
Depletion expense of evaluated oil and natural gas properties	$ 201,691	$ 203,492	$ 250,857
Depletion expense per BOE sold	$ 6.76	$ 6.34	$ 8.50

The full cost ceiling is based principally on the estimated future net cash flows from proved oil, NGL and natural gas reserves, which exclude the effect of the Company's commodity derivative transactions, discounted at 10%. SEC guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point ("Realized Prices") without giving effect to the Company's commodity derivative transactions. The Realized Prices are utilized to calculate the estimated future net cash flows in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is expensed in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible. The unamortized cost of evaluated oil and natural gas properties being depleted did not exceed the full cost ceiling during any of the quarterly periods in 2021.

The following table presents the Benchmark Prices and the Realized Prices as of the dates presented:

	December 31, 2021	December 31, 2020	December 31, 2019
Benchmark Prices:			
Oil ($/Bbl)	$ 63.04	$ 36.04	$ 52.19
NGL ($/Bbl)[(1)]	$ 34.51	$ 16.63	$ 21.14
Natural gas ($/MMBtu)	$ 3.35	$ 1.21	$ 0.87
Realized Prices:			
Oil ($/Bbl)	$ 66.37	$ 37.69	$ 52.12
NGL ($/Bbl)	$ 22.90	$ 7.43	$ 12.21
Natural gas ($/Mcf)	$ 2.61	$ 0.79	$ 0.53

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(1) Based on the Company's average composite NGL barrel.

The following table presents full cost ceiling impairment expense, which is included in "Impairment expense" on the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Full cost ceiling impairment expense	$ —	$ 889,453	$ 620,565

b. Midstream service assets

Midstream service assets, which consist of oil and natural gas pipeline gathering assets, related equipment, oil delivery stations, water storage and treatment facilities and their related asset retirement cost, are recorded at cost, net of impairment. See Note 2.k for discussion regarding midstream service asset retirement cost. Depreciation of assets is recorded using the straight-line method based on estimated useful lives of 10 to 20 years, as applicable. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations.

Midstream service assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Midstream service assets	$ 165,232	$ 181,718
Less accumulated depreciation and impairment	(68,704)	(69,021)
Total midstream service assets, net	$ 96,528	$ 112,697

During the year ended December 31, 2021, the Company retired $18.8 million in midstream service assets, resulting in the removal of $9.4 million in accumulated depreciation and the recognition of an associated loss of $9.4 million.

The following table presents depreciation of midstream service assets for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Depreciation of midstream service assets	$ 9,514	$ 9,838	$ 10,206

c. Other fixed assets

Other fixed assets are recorded at cost and are subject to depreciation and amortization. Land is recorded at cost and is not subject to depreciation. Depreciation and amortization of other fixed assets is provided using the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations.

Other fixed assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Computer hardware and software	$ 15,039	$ 9,388
Vehicles	9,072	9,852
Leasehold improvements	7,136	7,125
Buildings	7,039	6,982
Other	5,095	4,107
Depreciable total	43,381	37,454
Less accumulated depreciation and amortization	(27,692)	(24,344)
Depreciable total, net	15,689	13,110
Land	18,901	18,901
Total other fixed assets, net	$ 34,590	$ 32,011

The following table presents depreciation and amortization of other fixed assets for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Depreciation and amortization of other fixed assets	$ 4,150	$ 3,771	$ 4,683

Note 7 Debt

a. July 2029 Notes

On July 16, 2021, the Company completed a private offering and sale of $400.0 million in aggregate principal amount of 7.750% senior unsecured notes due 2029 (the "July 2029 Notes"). Interest for the July 2029 Notes is payable semi-annually, in cash in arrears on January 31 and July 31 of each year, commencing January 31, 2022 with interest from closing to that date. The terms of the July 2029 Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit the Company's ability to incur indebtedness, make restricted payments, grant liens and dispose of assets.

The July 2029 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the applicable indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the applicable indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The Company received net proceeds of approximately $392.0 million from the July 2029 Notes, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the offering were used for general corporate purposes, including repaying a portion of the borrowings outstanding under the Senior Secured Credit Facility.

b. January 2025 Notes and January 2028 Notes

On January 24, 2020, the Company completed an offer and sale (the "Offering") of $600.0 million in aggregate principal amount of 9.500% senior unsecured notes due 2025 (the "January 2025 Notes") and $400.0 million in aggregate principal amount of 10.125% senior unsecured notes due 2028 (the "January 2028 Notes"). Interest for both the January 2025 Notes and January 2028 Notes is payable semi-annually, in cash in arrears on January 15 and July 15 of each year. The first interest payment was made on July 15, 2020, and consisted of interest from closing to that date. The terms of the January 2025 Notes and January 2028 Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit the Company's ability to incur indebtedness, make restricted payments, grant liens and dispose of assets.

The January 2025 Notes and January 2028 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The Company received net proceeds of $982.0 million from the Offering, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the Offering were used (i) to fund Tender Offers (defined below) for the Company's January 2022 Notes and March 2023 Notes (defined below), (ii) to repay the Company's January 2022 Notes and March 2023 Notes that remained outstanding after settling the Tender Offers and (iii) for general corporate purposes, including repayment of a portion of the borrowings outstanding under the Company's Senior Secured Credit Facility.

In November 2020, the Company's board of directors authorized a $50.0 million bond repurchase program. During the year ended December 31, 2020, the Company repurchased $22.1 million in aggregate principal amount of the January 2025 Notes and $39.0 million in aggregate principal amount of the January 2028 Notes for aggregate consideration of $13.9 million and $24.2 million, respectively, plus accrued and unpaid interest. The Company recognized a gain on extinguishment of $22.3 million related to the difference between the consideration paid and the net carrying amounts of the extinguished portions of the January 2025 Notes and January 2028 Notes.

c. January 2022 Notes and March 2023 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). The January 2022 Notes were due to mature on January 15, 2022 and bore an interest rate of 5 5/8% per annum, payable semi-annually, in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes were fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On March 18, 2015, the Company completed an offering of $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"). The March 2023 Notes were due to mature on March 15, 2023 and bore an interest rate of 6 1/4% per annum, payable semi-annually, in cash in arrears on March 15 and September 15 of each year, commencing September 15, 2015. The March 2023 Notes were fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On January 6, 2020, the Company commenced cash tender offers and consent solicitations for any or all of its outstanding January 2022 Notes and March 2023 Notes (collectively, the "Tender Offers"). On January 24, 2020 and February 6, 2020, the Company settled the Tender Offers for the principal outstanding amounts of $428.9 million and $299.4 million, respectively, for consideration for tender offers and early tender premiums of $431.6 million and $304.1 million for the January 2022 Notes and March 2023 Notes, respectively, plus accrued and unpaid interest. On January 29, 2020, the Company redeemed the remaining $21.1 million of January 2022 Notes not tendered under the Tender Offers at a redemption price of 100.000% of the principal amount thereof, plus accrued and unpaid interest. On March 15, 2020, the Company redeemed the remaining $50.6 million of March 2023 Notes not tendered under the Tender Offers at a redemption price of 101.563% of the principal amount thereof, plus accrued and unpaid interest. The Company recognized a loss on extinguishment of $13.3 million related to the difference between the consideration for tender offers, early tender premiums and redemption prices and the net carrying amounts of the extinguished January 2022 Notes and March 2023 Notes.

d. Senior Secured Credit Facility

On May 7, 2021, the Company entered into the Sixth Amendment (the “Sixth Amendment”) to the Fifth Amended and Restated Credit Agreement, among the Company, as borrower, Wells Fargo Bank, N.A., as administrative agent, LMS and GCM, as guarantors, and the banks signatory thereto (as amended, the "Senior Secured Credit Facility"). The Sixth Amendment, among other things, reaffirmed the Senior Secured Credit Facility borrowing base at $725.0 million and amended the Senior Secured Credit Facility to permit (i) the Sabalo/Shad Acquisition and the other transactions contemplated by the Sabalo/Shad PSAs and (ii) the Working Interest Sale and the other transactions contemplated by the Sixth Street PSA, in each case, subject to the terms of the Sixth Amendment and the Senior Secured Credit Facility.

On July 16, 2021, the Company entered into the Seventh Amendment (the "Seventh Amendment") to the Senior Secured Credit Facility. The Seventh Amendment, among other things, included technical amendments (including in connection with Eurodollar advances), extended the maturity date by two years to July 16, 2025 (subject to a springing maturity date of July 29, 2024 if any of the January 2025 Notes are outstanding on such date), increased the applicable margins for advances made thereunder, increased certain commitment and letter of credit fees, revised certain exceptions to the limitations on the payment of distributions and the repayment of unsecured debt and decreased the leverage ratio for quarterly periods ending on and after September 30, 2021.

As of December 31, 2021, the Senior Secured Credit Facility, which matures on July 16, 2025 (subject to a springing maturity date of July 29, 2024 if any of the January 2025 Notes are outstanding on such date), had a maximum credit amount of $2.0 billion, a borrowing base of $1.0 billion and an aggregate elected commitment of $725.0 million, with $105.0 million outstanding and was subject to an interest rate of 2.625%. The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year based on the lenders' evaluation of the Company's oil, NGL and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 1.50% to 2.50%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at the Company's election, at the end of one-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate ("LIBOR") plus an applicable margin, which ranges from 2.50% to 3.50%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. Laredo is required to pay a quarterly commitment fee on the unused portion of the financial institutions' commitment of 0.5%.

The Senior Secured Credit Facility is secured by a first-priority lien on Laredo and the Guarantors' assets and stock, including oil and natural gas properties constituting at least 85% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial covenants on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, the Company must maintain as of the last day of each calendar quarter a ratio of (a) its total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of (i) not greater than 4.25 to 1.00 for quarterly periods ending on or prior to September 30, 2020, (ii) not greater than 4.00 to 1.00 for quarterly periods ending on or prior to March 31, 2021, (iii) not greater than 3.75 to 1.00 for the quarterly period ending on June 30, 2021 and (iv) not greater than 3.50 to 1.00 for quarterly periods ending on or after September 30, 2021. The Company was in compliance with these covenants for all periods presented. The Company's measurements of Adjusted EBITDA (non-GAAP) for financial reporting differs from the measurement used for compliance under its debt agreements.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2021 and 2020, the Company had one letter of credit outstanding of $44.1 million under the Senior Secured Credit Facility.

See Note 18.a for discussion of a borrowing and repayment on the Senior Secured Credit Facility subsequent to December 31, 2021.

e. Debt issuance costs

The following table presents debt issuance costs capitalized and debt issuance costs write-offs for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Debt issuance costs capitalized[1]	$ 14,686	$ 18,479	$ —
Debt issuance costs write-offs[2]	$ —	$ 6,163	$ 935

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(1) The Company capitalized $14.7 million in debt issuance costs during the year ended December 31, 2021 in connection with an increase in the borrowing base, entering into the Sixth and Seventh Amendments to the Senior Secured Credit Facility and the issuance of the July 2029 Notes. The Company capitalized $18.5 million in debt issuance costs during the year ended December 31, 2020 in connection with the issuance of the January 2025 Notes and January 2028 Notes and entering into amendments to the Senior Secured Credit facility in connection with the semi-annual redeterminations.

(2) The Company wrote off $1.1 million and $0.9 million of debt issuance costs during the years ended December 31, 2020 and 2019, respectively, which are the "Write-off of debt issuance costs" on the consolidated statements of operations, in connection with reductions in borrowing base and aggregate elected commitment under the Senior Secured Credit Facility in connection with the semi-annual redeterminations. The Company wrote off $5.1 million in debt issuance costs during the year ended December 31, 2020, which are included in "Gain on extinguishment of debt, net" on the consolidated statement of operations, in connection with the extinguishment of the January 2022 Notes and March 2023 Notes and portions of the January 2025 Notes and January 2028 Notes.

The Company had total debt issuance costs of $26.2 million and $17.0 million, net of accumulated amortization of $27.2 million and $22.1 million, as of December 31, 2021 and 2020, respectively. Debt issuance costs related to the Company's January 2025 Notes, January 2028 Notes and July 2029 Notes are included in "Long-term debt, net" on the consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are included in "Other noncurrent assets, net" on the consolidated balance sheets. Debt issuance costs are amortized on a straight-line basis over the respective terms of the notes and the Senior Secured Credit Facility. See Note 7.g for additional discussion of debt issuance costs.

The following table presents future amortization expense of debt issuance costs:

(in thousands)	December 31, 2021
2022	6,165
2023	6,165
2024	6,165
2025	2,894
2026	1,735
Thereafter	3,079
Total	26,203

f. Interest expense

The following table presents amounts that have been incurred and charged to interest expense:

(in thousands)	Years ended December 31, 2021	2020	2019
Cash payments for interest	$ 100,733	$ 80,420	$ 59,021
Amortization of debt issuance costs and other adjustments	4,451	3,708	3,111
Change in accrued interest	14,067	23,900	220
Interest costs incurred	119,251	108,028	62,352
Less capitalized interest	(5,866)	(3,019)	(805)
Total interest expense	$ 113,385	$ 105,009	$ 61,547

g. Long-term debt, net

The following table presents the Company's long-term debt and debt issuance costs, net included in "Long-term debt, net" on the consolidated balance sheets as of the dates presented:

	December 31, 2021			December 31, 2020		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2025 Notes	577,913	(6,345)	571,568	577,913	(8,676)	569,237
January 2028 Notes	361,044	(5,024)	356,020	361,044	(6,015)	355,029
July 2029 Notes	400,000	(6,730)	393,270	—	—	—
Senior Secured Credit Facility(1)	105,000	—	105,000	255,000	—	255,000
Total	$ 1,443,957	$ (18,099)	$ 1,425,858	$ 1,193,957	$ (14,691)	$ 1,179,266

(1) Debt issuance costs, net related to the Senior Secured Credit Facility of $8.1 million and $2.3 million as of December 31, 2021 and 2020, respectively, are included in "Other noncurrent assets, net" on the consolidated balance sheets.

Note 8 Stockholders' equity

a. ATM Program

On February 23, 2021, the Company entered into an equity distribution agreement (the "Equity Distribution Agreement") with Wells Fargo Securities, LLC acting as sales agent and/or principal (the "Sales Agent"), pursuant to which the Company may offer and sell, from time to time through the Sales Agent, shares of its common stock having an aggregate gross sales price of up to $75.0 million through an "at-the-market" equity program (the "ATM Program").

Pursuant to the Equity Distribution Agreement, shares of common stock may be offered and sold in privately negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 under the Securities Act, including by ordinary brokers' transactions through the facilities of the New York Stock Exchange, to or through a market maker or as otherwise agreed with the Sales Agent. Under the terms of the Equity Distribution Agreement, the Company may also sell common stock from time to time to the Sales Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common stock to the Sales Agent as principal would be pursuant to the terms of a separate terms agreement between the Company and the Sales Agent, which would be described in a separate prospectus supplement or pricing supplement.

As of December 31, 2021, the Company has sold 1,438,105 shares of its common stock pursuant to the ATM Program for net proceeds of approximately $72.5 million, after underwriting commissions and other related expenses, thus completing the ATM Program. Proceeds from the share sales were utilized to reduce borrowings on the Senior Secured Credit Facility.

b. Reverse stock split and Authorized Share Reduction

On March 17, 2020, the board of directors authorized an amendment to the Company's amended and restated certificate of incorporation ("Certificate of Incorporation") to effect, at the discretion of the board of directors (i) a reverse stock split that would reduce the number of shares of outstanding common stock in accordance with a ratio to be determined by the board of directors within a range of 1-for-5 and 1-for-20 currently outstanding and (ii) a reduction of the number of authorized shares of common stock by a corresponding proportion ("Authorized Share Reduction").

On May 14, 2020, after receiving stockholder approval of the amendment to the Certificate of Incorporation, the board of directors approved the implementation of the reverse stock split at a ratio of 1-for-20 currently outstanding shares of common stock, and the related corresponding Authorized Share Reduction.

On June 1, 2020, the amendment to the Company's Certificate of Incorporation became effective and effected the 1-for-20 reverse stock split of the Company's issued and outstanding common stock and the related Authorized Share Reduction from 450,000,000 to 22,500,000 authorized shares, par value $0.01 per share, with authorized shares of preferred stock remaining unchanged at 50,000,000, par value $0.01 per share, for a total of 72,500,000 shares of capital stock. See Note 9.a for discussion of the Laredo Petroleum, Inc. Omnibus Equity Incentive Plan (the "Equity Incentive Plan"), that proportionately reduced the number of shares that may be granted.

Note 9 Compensation plans

a. Equity Incentive Plan

The Equity Incentive Plan provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, outperformance share awards, performance unit awards, phantom unit awards and other awards. On June 1, 2020, in connection with the effectiveness of the reverse stock split and Authorized Share Reduction, the board of directors approved and adopted an amendment to the Equity Incentive Plan to proportionately adjust the limitations on awards that may be granted under the Equity Incentive Plan. Following the amendment, an aggregate of 1,492,500 shares may be issued under the Equity Incentive Plan. See Note 8.b for additional discussion of the reverse stock split and Authorized Share Reduction. On May 20, 2021, the Company's stockholders approved an amendment to the Equity Incentive Plan to, among other things, increase the maximum number of shares of the Company's common stock issuable under the Equity Incentive Plan from 1,492,500 to 2,432,500 shares.

See Note 2.p for discussion of the Company's significant accounting policies for equity-based compensation awards.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the consolidated financial statements. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the restricted stock awards are forfeited and canceled and are no longer considered issued and outstanding. If the termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to employees vest in a variety of schedules that mainly include (i) 33%, 33% and 34% vesting per year beginning on the first anniversary of the grant date and (ii) full vesting on the first anniversary of the grant date. Restricted stock awards granted to non-employee directors vest immediately on the grant date.

The following table reflects the restricted stock award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Restricted stock awards	Weighted-average grant-date fair value (per share)
Outstanding as of December 31, 2018	210	$ 198.20
Granted	381	$ 65.20
Forfeited	(178)	$ 102.20
Vested	(138)	$ 178.40
Outstanding as of December 31, 2019	275	$ 85.80
Granted	238	$ 16.54
Forfeited	(48)	$ 53.51
Vested	(156)	$ 71.25
Outstanding as of December 31, 2020	309	$ 44.88
Granted	237	$ 38.86
Forfeited	(42)	$ 42.44
Vested[1]	(154)	$ 57.37
Outstanding as of December 31, 2021	350	$ 35.57

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(1) The aggregate intrinsic value of vested restricted stock awards for the year ended December 31, 2021 was $7.3 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of restricted stock awards. As of December 31, 2021, unrecognized equity-based compensation related to the restricted stock awards expected to vest was $7.2 million. Such cost is expected to be recognized over a weighted-average period of 1.94 years.

Stock option awards

The following table reflects the stock option award activity for the years presented:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards	Weighted-average exercise price (per share)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2018	127	$ 253.80	5.99
Exercised	(1)	$ 82.00	
Expired or canceled	(92)	$ 271.00	
Forfeited	(17)	$ 172.20	
Outstanding as of December 31, 2019	17	$ 251.20	5.00
Expired or canceled	(6)	$ 238.38	
Outstanding as of December 31, 2020	11	$ 257.42	4.00
Exercised	(2)	$ 82.00	
Expired or canceled	(2)	$ 374.77	
Outstanding and exercisable as of December 31, 2021[1]	7	$ 275.88	3.24

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(1) The vested and exercisable stock option awards as of December 31, 2021 had no intrinsic value.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and recognizes the associated expense on a straight-line basis over the four-year requisite service period of the awards. Stock option awards granted to employees vest and become exercisable in four equal installments on each of the four anniversaries of the grant date, in accordance with the following schedule:

Full years of continuous employment following grant date	Incremental percentage of option exercisable	Cumulative percentage of option exercisable
Less than one	— %	— %
One	25 %	25 %
Two	25 %	50 %
Three	25 %	75 %
Four	25 %	100 %

Unless employment is terminated sooner, the vested stock option award will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of a stock option award shall forfeit upon termination of employment, and the vested portion of a stock option award shall remain exercisable for (i) one year following termination of employment by reason of the holder's death or disability, but not later than the expiration of the option period, or (ii) 90 days following termination of employment for any reason other than the holder's death or disability, and other than the holder's termination of employment for cause. The vested but unexercised portion of a stock option award shall expire upon the termination of the option holder's employment or service by the Company for cause.

Performance share awards

Performance share awards, which the Company has determined are equity awards, are subject to a combination of market, performance and service vesting criteria. For portions of awards with market criteria, a Monte Carlo simulation prepared by an independent third party is utilized to determine the grant-date (or modification date) fair value, and the associated expense is recognized on a straight-line basis over the three-year requisite service period of the awards. For portions of awards with performance criteria, the fair value is equal to the Company's closing stock price on the grant date (or modification date), and for each reporting period, the associated expense fluctuates and is adjusted based on an estimated payout of the number of shares of common stock to be delivered on the payment date for the three-year performance period.

These awards were granted in 2019 and 2018, and their market criteria consists of: (i) the relative three-year total shareholder return ("TSR") comparing the Company's shareholder return to the shareholder return of the peer group specified in each award agreement ("RTSR Performance Percentage"), and (ii) the Company's absolute three-year total shareholder return ("ATSR Appreciation"). The performance criteria for these awards consists of the Company's three-year return on average capital employed ("ROACE Percentage"). Any shares earned under performance share awards are expected to be issued in the first quarter following the completion of the respective requisite service periods based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance share awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance share awards will receive a prorated number of shares based on the number of days the participant was employed with the Company during the performance period.

The following table reflects the performance share award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Performance share awards	Weighted-average grant-date fair value (per share)
Outstanding as of December 31, 2018	172	$ 274.80
Granted[1]	29	$ 50.40
Converted from performance unit awards[1][2]	78	$ 74.80
Forfeited	(87)	$ 209.60
Lapsed[3]	(77)	$ 346.20
Outstanding as of December 31, 2019	115	$ 106.80
Forfeited	(10)	$ 110.94
Lapsed[4]	(8)	$ 379.20
Outstanding as of December 31, 2020	97	$ 84.06
Forfeited	(10)	$ 74.70
Vested[1]	(15)	$ 184.43
Outstanding as of December 31, 2021	72	$ 64.74

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(1) The amounts payable in the Company's common stock at the end of the requisite service period for the performance share awards granted on February 16, 2018, February 28, 2019 and June 3, 2019 were determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the number of shares to be delivered on the payment date. In computing the Performance Multiple, the RTSR Factor is given a 25% weight, the ATSR Factor a 25% weight and the ROACE Factor a 50% weight. The performance share awards granted on February 16, 2018 had a performance period of January 1, 2018 to December 31, 2020 and, as their market and performance criteria were partially satisfied, resulted in a 43% payout. Based on such payout, the granted awards vested and were converted into 6,343 shares of the Company's common stock during the year ended December 31, 2021. The performance share awards granted on February 28, 2019 and June 3, 2019 had a performance period of January 1, 2019 to December 31, 2021 and, as their market and performance criteria were fully satisfied, resulted in a 107% payout. Based on such payout, the granted awards will be converted into shares of the Company's common stock during the first quarter of 2022.

(2) On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock for the awards granted on February 28, 2019. This change in election triggered modification accounting, and the awards, formerly accounted for as liability awards, were converted to equity awards and, accordingly, new fair values were determined based on the May 16, 2019 modification date.

(3) The performance share awards granted on May 25, 2016 had a performance period of January 1, 2016 to December 31, 2018 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the ninth percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of 2019.

(4) The performance share awards granted on February 17, 2017 had a performance period of January 1, 2017 to December 31, 2019 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 15th percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of 2020.

As of December 31, 2021, unrecognized equity-based compensation related to the performance share awards expected to vest was $0.3 million. Such cost is expected to be recognized over a weighted-average period of 0.16 years.

The following table presents (i) the fair values per performance share and the assumptions used to estimate these fair values per performance share and (ii) the expense per performance share, which is the fair value per performance share adjusted for the estimated payout of the performance criteria, for the outstanding performance share awards as of December 31, 2021 for the grant dates presented:

	June 3, 2019	February 28, 2019[(1)]
Market Criteria:		
25% RTSR Factor + 25% ATSR Factor:		
Fair value assumptions:		
Remaining performance period on grant date	2.58 years	2.63 years
Risk-free interest rate[(2)]	1.78 %	2.14 %
Dividend yield	— %	— %
Expected volatility[(3)]	55.45 %	55.01 %
Closing stock price on grant date	$ 51.80	$ 69.80
Grant-date fair value per performance share	$ 49.00	$ 79.61
Expense per performance share as of December 31, 2021	$ 49.00	$ 79.61
Performance Criteria:		
50% ROACE Factor:		
Fair value assumptions:		
Closing stock price on grant date	$ 51.80	$ 69.80
Grant-date fair value per performance share	$ 51.80	$ 69.80
Estimated payout for expense as of December 31, 2021	160 %	160 %
Expense per performance share as of December 31, 2021[(4)]	$ 82.88	$ 111.68
Combined:		
Grant-date fair value per performance share[(5)]	$ 65.94	$ 95.65
Expense per performance share as of December 31, 2021[(6)]	$ 65.94	$ 95.65

(1) The fair value assumptions of the performance share awards granted on February 28, 2019 are based on the May 16, 2019 modification date. The total incremental compensation expense resulting from the modification of $1.0 million, which will be recognized over the life of the awards, is calculated utilizing (i) the difference between the March 31, 2019 fair value and the May 16, 2019 fair value and (ii) the outstanding quantity of the converted performance share awards as of June 30, 2019. Such expense excludes the estimated payout component for expense for the 50% ROACE Factor as this is redetermined at each reporting period and the expense will fluctuate accordingly.

(2) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date for each respective award, with the exception of the awards granted on February 28, 2019, which used the modification date of May 16, 2019.

(3) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(4) As the 50% ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the respective awards is adjusted accordingly.

(5) The combined grant-date fair value per performance share is the combination of the fair value per performance share weighted for the market and performance criteria for the respective awards.

(6) The combined expense per performance share is the combination of the expense per performance share weighted for the market and performance criteria for the respective awards.

Outperformance share award

An outperformance share award was granted during the year ended December 31, 2019, in conjunction with the appointment of the Company's President, and is accounted for as an equity award. If earned, the payout ranges from 0 to 50,000 shares in the Company's common stock per the vesting schedule. This award is subject to a combination of market and service vesting criteria and, therefore, a Monte Carlo simulation prepared by an independent third party was utilized to determine the grant-date fair value with the associated expense recognized over the requisite service period. The payout of this award is based on the highest 50 consecutive trading day average closing stock price of the Company that occurs during the performance period that commenced on June 3, 2019 and ends on June 3, 2022 ("Final Date"). Of the earned outperformance shares, one-third of the award will vest on the Final Date, one-third will vest on the first anniversary of the Final Date and one-third will vest on the second anniversary of the Final Date, provided that the participant has been continuously employed with the Company through the applicable vesting date. Per the award agreement terms, if employment is terminated prior to any vesting date for reasons other than death or disability, then any outperformance shares that have not vested as of such date shall be forfeited and canceled. If the participant's employment is terminated prior to any vesting date by reason of death or disability, and the market criteria is satisfied, then the participant will receive a prorated number of shares based on the number of days the employee was employed with the Company during the performance period.

The total fair value of the outperformance share award and the assumptions used to estimate the fair value of the outperformance share award as of the grant date presented are as follows:

	June 3, 2019
Performance period	3.00 years
Risk-free interest rate(1)	1.77 %
Dividend yield	— %
Expected volatility(2)	55.77 %
Closing stock price on grant date	$ 51.80
Total fair value of outperformance share award (in thousands)	$ 670.0

(1) The performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date.

(2) The Company utilized its own performance period matched historical volatility in order to develop the expected volatility.

As of December 31, 2021, unrecognized equity-based compensation related to the outperformance share award expected to vest was $0.2 million. Such cost is expected to be recognized over a weighted-average period of 1.78 years.

Performance unit awards

Performance unit awards, which the Company has determined are liability awards since they are settled in cash, are subject to a combination of market, performance and service vesting criteria. For portions of awards with market criteria, a Monte Carlo simulation prepared by an independent third party is utilized to determine the fair value, and is re-measured at each reporting period until settlement. For portions of awards with performance criteria, the Company's closing stock price is utilized to determine the fair value and is re-measured on the last trading day of each reporting period until settlement and, additionally, the associated expense fluctuates based on an estimated payout for the three-year performance period. The expense related to the performance unit awards is recognized on a straight-line basis over the three-year requisite service period of the awards, and the life-to-date recognized expense is adjusted accordingly at each reporting period based on the quarterly fair value re-measurements and redetermination of the estimated payout for the performance criteria.

For performance unit awards granted in 2021, the market criteria consists of: (i) annual relative shareholder return comparing the Company's shareholder return to the shareholder return of the E&P companies listed in the Russell 2000 index ("Relative TSR") and (ii) annual absolute total shareholder return ("Absolute Return"), together the "PSU Matrix". The performance criteria for these awards consists of: (i) earnings before interest , taxes, depreciation, amortization and exploration expense ("EBITDAX") and three-year total debt reduction (the "EBITDAX/Total Debt Component") and (ii) growth in inventory (the "Inventory Growth Component"). Any units earned are expected to be paid in cash during the first quarter following the completion of the requisite service period, based on the achievement of certain market and performance criteria, and the payout can range from 0% to 250% for the market criteria and 0% to 200% for the performance criteria.

For performance unit awards granted in 2020, the market criteria consists of: (i) the RTSR Performance Percentage and (ii) the ATSR Appreciation. The performance criteria for these awards consists of the ROACE Percentage. Any units earned, are expected to be paid in cash during the first quarter following the completion of the requisite service period, based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%, but is capped at 100% if the ATSR Appreciation is zero or less.

Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance unit awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance unit awards will receive a prorated payment based on the number of days the participant was employed with the Company during the performance period.

The following table reflects the performance unit award activity for the years presented:

(in thousands)	Performance units
Outstanding as of December 31, 2019	—
Granted(1)	123
Forfeited	(24)
Outstanding as of December 31, 2020	99
Granted(2)	110
Outstanding as of December 31, 2021	209

(1) The amounts potentially payable in cash at the end of the requisite service period for the performance unit awards granted on March 5, 2020 will be determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the final value of each performance unit to be paid in cash on the payment date per the award agreement, subject to withholding requirements. In computing the Performance Multiple, the RTSR Factor is given a 1/3 weight, the ATSR Factor a 1/3 weight and the ROACE Factor a 1/3 weight. These awards have a performance period of January 1, 2020 to December 31, 2022.

(2) The amounts potentially payable in cash at the end of the requisite service period for the performance unit awards granted on March 9, 2021 will be determined based on three criteria: (i) the PSU Matrix, (ii) the EBITDAX/Total Debt Component and (iii) the Inventory Growth Component. These criteria are used to compute the "Performance Multiple" and ultimately to determine the final value of each performance unit to be paid in cash on the payment date per the award agreement, subject to withholding requirements. In computing the Performance Multiple, the PSU Matrix is given a 50% weight, the EBITDAX/Total Debt Component a 25% weight and the Inventory Growth Component a 25% weight. These awards have a performance period of January 1, 2021 to December 31, 2023.

The following tables present (i) the fair values per performance unit and the assumptions used to estimate these fair values per performance unit and (ii) the expense per performance unit, which is the fair value per performance unit adjusted for the estimated payout of the performance criteria, for the outstanding performance unit awards as of December 31, 2021 for the grant dates presented:

		March 5, 2020
Market criteria:		
1/3 RTSR Factor + 1/3 ATSR Factor:		
Fair value assumptions:		
Remaining performance period		1.00 year
Risk-free interest rate[(1)]		0.39 %
Dividend yield		— %
Expected volatility[(2)]		86.17 %
Closing stock price on December 31, 2021	$	60.13
Fair value per performance unit as of December 31, 2021	$	195.77
Expense per performance unit as of December 31, 2021	$	195.77
Performance criteria:		
1/3 ROACE Factor:		
Fair value assumptions:		
Closing stock price on December 31, 2021	$	60.13
Fair value per performance unit as of December 31, 2021	$	60.13
Estimated payout for expense as of December 31, 2021		130.00 %
Expense per performance unit as of December 31, 2021[(3)]	$	78.17
Combined:		
Fair value per performance unit as of December 31, 2021[(4)]	$	91.31
Expense per performance unit as of December 31, 2021[(5)]	$	91.31

(1) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on December 31, 2021.

(2) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(3) As the 1/3 ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the award is adjusted accordingly.

(4) The combined fair value per performance unit is the combination of the fair value per performance unit weighted for the market and performance criteria for the award.

(5) The combined expense per performance unit is the combination of the expense per performance unit weighted for the market and performance criteria for the award.

		March 9, 2021
Market criteria:		
50% PSU Matrix Component:		
Fair value assumptions:		
Remaining performance period		2.00 years
Risk-free interest rate(1)		0.73 %
Dividend yield		— %
Expected volatility(2)		135.42 %
Closing stock price on December 31, 2021	$	60.13
Fair value per performance unit as of December 31, 2021	$	121.72
Expense per performance unit as of December 31, 2021	$	121.72
Performance criteria:		
25% EBITDAX/Total Debt Component + 25% Inventory Growth Component		
Fair value assumptions:		
Closing stock price on December 31, 2021	$	60.13
Fair value per performance unit as of December 31, 2021	$	60.13
Estimated payout for expense as of December 31, 2021		100.00 %
Expense per performance unit as of December 31, 2021(3)	$	60.13
Combined:		
Fair value per performance unit as of December 31, 2021(4)	$	90.92
Expense per performance unit as of December 31, 2021(5)	$	90.92

(1) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on December 31, 2021.

(2) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(3) As the 25% EBITDAX/Total Debt Component and 25% Inventory Growth Component are based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the award is adjusted accordingly.

(4) The combined fair value per performance unit is the combination of the fair value per performance unit weighted for the market and performance criteria for the award.

(5) The combined expense per performance unit is the combination of the expense per performance unit weighted for the market and performance criteria for the award.

As of December 31, 2021, unrecognized equity-based compensation related to the performance unit awards expected to vest was $10.8 million. Such cost is expected to be recognized over a weighted-average period of 1.86 years.

Phantom unit awards

Phantom unit awards, which the Company has determined are liability awards, represent the holder's right to receive the cash equivalent of one share of common stock of the Company for each phantom unit as of the applicable vesting date, subject to withholding requirements. Phantom unit awards granted to employees vest 33%, 33% and 34% per year beginning on the first anniversary of the grant date. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the phantom unit awards are forfeited and canceled. If the termination of employment is by reason of death or disability, all of the holder's phantom unit awards automatically vest.

The following table reflects the phantom unit award activity for the year ended December 31, 2021:

(in thousands, except for weighted-average fair value)	Phantom units
Outstanding as of December 31, 2019	—
Granted	75
Outstanding as of December 31, 2020	75
Granted	5
Forfeited	(22)
Vested[(1)]	(25)
Outstanding as of December 31, 2021[(2)]	33

(1) On March 5, 2021, the vested phantom unit awards were settled and paid out in cash at a fair value per unit of $34.24 based on the Company's closing stock price on the vesting date.

(2) The fair value per unit of outstanding phantom unit awards as of December 31, 2021 was $60.13.

The Company utilizes the closing stock price on the last day of each reporting period to determine the fair value of phantom unit awards and the life-to-date recognized expense is adjusted accordingly. As of December 31, 2021, unrecognized equity-based compensation related to the phantom unit awards expected to vest was $1.2 million. Such cost is expected to be recognized over a weighted-average period of 1.34 years.

Equity-based compensation

The following table reflects equity-based compensation expense for the years presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Equity awards:			
Restricted stock awards	$ 7,594	$ 8,839	$ 13,169
Performance share awards	1,482	2,545	(1,250)
Outperformance share award	175	174	101
Stock option awards	7	77	740
Total share-settled equity-based compensation, gross	$ 9,258	$ 11,635	$ 12,760
Less amounts capitalized	(1,583)	(3,418)	(4,470)
Total share-settled equity-based compensation, net	$ 7,675	$ 8,217	$ 8,290
Liability awards:			
Performance unit awards	$ 7,480	$ 749	$ —
Phantom unit awards	1,238	404	—
Total cash-settled equity-based compensation, gross	$ 8,718	$ 1,153	$ —
Less amounts capitalized	(365)	(163)	—
Total cash-settled equity-based compensation, net	$ 8,353	$ 990	$ —
Total equity-based compensation, net	$ 16,028	$ 9,207	$ 8,290

See Note 17 for discussion of the Company's organizational restructurings and the related equity-based compensation reversals during the years ended December 31, 2021, 2020 and 2019.

b. 401(k) plan

The Company sponsors a 401(k) plan that is a defined contribution plan for the benefit of all employees at the date of hire. The plan allows eligible employees to make pre-tax and after-tax contributions up to 100% of their annual eligible compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt.

The following table presents the contributions expense recognized for the Company's 401(k) plan for the years presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Contributions	$ 1,652	$ 1,649	$ 1,742

Note 10 Derivatives

The Company has three types of derivative instruments as of December 31, 2021: (i) commodity derivatives, (ii) a debt interest rate derivative and (iii) a contingent consideration derivative. See Notes (i) 2.e for the Company's significant accounting policies for derivatives and presentation in the consolidated financial statements, (ii) 11.a for fair value measurement of derivatives on a recurring basis and (iii) 18.b for derivatives subsequent events.

The following table summarizes the Company's gain (loss) on derivatives, net by type of derivative instrument for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Commodity	$ (453,784)	$ 73,662	$ 80,351
Interest rate	(30)	(343)	—
Contingent consideration	1,639	6,795	(1,200)
Gain (loss) on derivatives, net	$ (452,175)	$ 80,114	$ 79,151

a. Commodity

Due to the inherent volatility in oil, NGL and natural gas prices and the sometimes wide pricing differences in the prices of oil, NGL and natural gas between where the Company produces and where the Company sells such commodities, the Company engages in commodity derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of the Company's anticipated sales volumes. By removing a portion of the price volatility associated with future sales volumes, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

Each put transaction has an established floor price. The Company pays its counterparty a premium, which can be paid at inception or deferred until settlement, to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Company an amount equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is at or above the floor price in an individual month in the contract period, the put option expires with no settlement for that particular month, except with regard to the deferred premium, if any.

Each swap transaction has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

Each collar transaction has an established price floor and ceiling. Depending on the terms, the Company may pay its counterparty a premium, which can be paid at inception or deferred until settlement. When the settlement price is below the price floor established by these collars, the counterparty pays the Company an amount equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is at or between the price floor and price ceiling established by these collars in an individual month in the contract period, the collar expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Each basis swap transaction has an established fixed basis differential corresponding to two floating index prices. When the settlement basis differential is below the fixed basis differential, the counterparty pays the Company an amount equal to the difference between the fixed basis differential and the settlement basis differential multiplied by the hedged contract volume. When the settlement basis differential is above the fixed basis differential, the Company pays the counterparty an amount equal to the difference between the settlement basis differential and the fixed basis differential multiplied by the hedged contract volume.

During the year ended December 31, 2021, the Company's derivatives were settled based on reported prices on commodity exchanges, with (i) oil derivatives settled based on WTI NYMEX pricing and Brent ICE pricing, (ii) NGL derivatives settled based on Mont Belvieu OPIS pricing and (iii) natural gas derivatives settled based on Henry Hub NYMEX and Waha Inside FERC pricing.

During the year ended December 31, 2021, in connection with the Working Interest Sale, the Company entered into derivative positions on behalf of Sixth Street. Following the closing of the Working Interest Sale on July 1, 2021, all of the hedges entered into on behalf of Sixth Street were novated to Sixth Street as intended.

During the year ended December 31, 2021, the Company completed a hedge restructuring by (i) selling 2,254,500 calendar year 2021 $55.00 per barrel Brent ICE puts, which volumetrically offset existing calendar year 2021 $55.00 per barrel Brent ICE puts, and receiving aggregate premiums of $9.0 million at inception of the contracts and (ii) entering into 2,254,500 calendar year 2021 Brent ICE swaps at a weighted-average price of $55.09 per barrel. Associated with the aforementioned existing calendar year 2021 $55.00 per barrel Brent ICE puts, which were entered into during 2020, were $50.6 million in aggregate premiums paid at the inception of the contracts.

During the year ended December 31, 2020, the Company completed hedge restructurings by (i) early terminating collars and entering into new swaps and (ii) early terminating swaps resulting in proceeds of $6.3 million. The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
WTI NYMEX - Swaps	389,180	$ 60.25	$ 60.25	September 2020 - December 2020
WTI NYMEX - Collars	912,500	$ 45.00	$ 71.00	January 2021 - December 2021

During the year ended December 31, 2019, the Company completed hedge restructurings by early terminating puts and collars and entering into new swaps. The Company paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with a portion of these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million. See Note 11 for information about the fair value hierarchy levels. The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
WTI NYMEX - Puts	5,087,500	$ 46.03	$ —	April 2019 - December 2019
WTI NYMEX - Put	366,000	$ 45.00	$ —	January 2020 - December 2020
WTI NYMEX - Collars	1,134,600	$ 45.00	$ 76.13	January 2020 - December 2020

The following table summarizes open commodity derivative positions as of December 31, 2021, for commodity derivatives that were entered into through December 31, 2021, for the settlement periods presented:

	Year 2022	Year 2023
Oil:		
WTI NYMEX - Swaps:		
Volume (Bbl)	1,085,000	—
Weighted-average price ($/Bbl)	$ 67.77	$ —
WTI NYMEX - Collars:		
Volume (Bbl)	3,394,500	730,000
Weighted-average floor price ($/Bbl)	$ 58.23	$ 60.00
Weighted-average ceiling price ($/Bbl)	$ 69.39	$ 75.66
Total WTI NYMEX:		
Total volume (Bbl)	4,479,500	730,000
Weighted-average floor price ($/Bbl)	$ 60.54	$ 60.00
Weighted-average ceiling price ($/Bbl)	$ 69.00	$ 75.66
Brent ICE - Swaps:		
Volume (Bbl)	4,124,500	—
Weighted-average price ($/Bbl)	$ 48.34	$ —
Brent ICE - Collars:		
Volume (Bbl)	1,551,250	—
Weighted-average floor price ($/Bbl)	$ 56.65	$ —
Weighted-average ceiling price ($/Bbl)	$ 65.44	$ —
Total Brent ICE:		
Total volume (Bbl)	5,675,750	—
Weighted-average floor price ($/Bbl)	$ 50.61	$ —
Weighted-average ceiling price ($/Bbl)	$ 53.01	$ —
NGL:		
Purity Ethane - Swaps:		
Volume (Bbl)	1,533,000	—
Weighted-average price ($/Bbl)	$ 11.42	$ —
Non-TET Propane - Swaps:		
Volume (Bbl)	1,168,000	—
Weighted-average price ($/Bbl)	$ 35.91	$ —
Non-TET Normal Butane - Swaps:		
Volume (Bbl)	365,000	—
Weighted-average price ($/Bbl)	$ 41.58	$ —
Non-TET Isobutane - Swaps:		
Volume (Bbl)	109,500	—
Weighted-average price ($/Bbl)	$ 42.00	$ —
Non-TET Natural Gasoline - Swaps:		
Volume (Bbl)	365,000	—
Weighted-average price ($/Bbl)	$ 60.65	$ —
Total NGL volume (Bbl)	3,540,500	—
CONTINUED ON NEXT PAGE		

	Year 2022		Year 2023	
Natural gas:				
Henry Hub NYMEX - Swaps:				
Volume (MMBtu)		3,650,000		—
Weighted-average price ($/MMBtu)	$	2.73	$	—
Henry Hub NYMEX - Collars:				
Volume (MMBtu)		29,200,000		3,650,000
Weighted-average floor price ($/MMBtu)	$	3.09	$	3.00
Weighted-average ceiling price ($/MMBtu)	$	3.84	$	4.45
Total Henry Hub NYMEX:				
Total volume (MMBtu)		32,850,000		3,650,000
Weighted-average floor price ($/MMBtu)	$	3.05	$	3.00
Weighted-average ceiling price ($/MMBtu)	$	3.71	$	4.45
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps:				
Volume (MMBtu)		29,017,500		—
Weighted-average differential ($/MMBtu)	$	(0.36)	$	—

b. Interest rate

Due to the inherent volatility in interest rates, the Company has entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of the Company's anticipated outstanding debt under the Senior Secured Credit Facility. The Company will pay a fixed rate over the contract term for that portion. By removing a portion of the interest rate volatility associated with anticipated outstanding debt, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. The following table summarizes the Company's interest rate derivative:

	Notional amount (in thousands)		Fixed rate	Contract period
LIBOR - Swap	$	100,000	0.345 %	April 16, 2020 - April 18, 2022

c. Contingent consideration

The Sixth Street PSA provided for potential contingent payments to be paid to the Company if certain cash flow targets are met related to divested oil and natural gas property operations. The Sixth Street Contingent Consideration provides the Company with the right to receive up to a maximum of $93.7 million in additional cash consideration, comprised of potential quarterly payments through June 2027 totaling up to $38.7 million and a potential balloon payment of $55.0 million in June 2027. The fair value of the Sixth Street Contingent Consideration was determined to be $33.8 million as of the Sixth Street Closing Date and $35.9 million as of December 31, 2021.

The Company's asset acquisition of oil and natural gas properties that closed on April 30, 2020 provided for potential contingent payments to be paid by the Company if the arithmetic average of the monthly settlement WTI NYMEX prices exceed certain thresholds for the contingency period beginning on January 1, 2021 and ending on the earlier of December 31, 2022 or the date the counterparty has received the maximum consideration of $1.2 million. As the maximum thresholds were met, the Company paid the maximum amount of the $1.2 million contingent consideration to the counterparty during the year ended December 31, 2021.

The Company's acquisition of oil and natural gas properties that closed on December 12, 2019 provided for a potential contingent payment. If the arithmetic average of the monthly settlement WTI NYMEX prices exceeded a certain threshold for the contingency period beginning on January 1, 2020 and ending on December 31, 2020, the Company would have been required to pay to the counterparty an amount equal to $20.0 million. As the provisions for this contingent payment were not met, no payment by the Company was required.

See Notes 4.a, 4.b and 4.d for further discussion of the Company's acquisitions and divestiture with potential contingent consideration. At each quarterly reporting period, the Company remeasures outstanding contingent considerations with the change in fair values recognized in earnings.

Note 11 Fair value measurements

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation techniques, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on inputs to the valuation techniques as follows:

Level 1— Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2— Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the assets or liabilities. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3— Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs are not corroborated by market data. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

a. Fair value measurement on a recurring basis

For further discussion of the Company's derivatives, see Notes (i) 2.e for the Company's significant accounting policies for derivatives, (ii) 10 for derivatives and (iii) 18.b for derivatives subsequent events.

Balance sheet presentation

The following tables present the Company's derivatives by (i) balance sheet classification, (ii) derivative type and (iii) fair value hierarchy level, and provide a total, on a gross basis and a net basis reflected in "Derivatives" on the consolidated balance sheets as of the dates presented:

	December 31, 2021					
(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 14,653	$ —	$ 14,653	$ (14,653)	$ —
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	7,018	—	7,018	(7,018)	—
Contingent consideration	—	—	4,346	4,346	—	4,346
Noncurrent:						
Commodity - Oil	$ —	$ 1,196	$ —	$ 1,196	$ —	$ 1,196
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	252	—	252	—	252
Contingent consideration	—	—	31,515	31,515	—	31,515
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (167,749)	$ —	$ (167,749)	$ 14,653	$ (153,096)
Commodity - NGL	—	(17,581)	—	(17,581)	—	(17,581)
Commodity - Natural gas	—	(16,098)	—	(16,098)	7,018	(9,080)
Interest rate - LIBOR	—	(52)	—	(52)	—	(52)
Contingent consideration	—	—	—	—	—	—
Noncurrent:						
Commodity - Oil	$ —	$ —	$ —	$ —	$ —	$ —
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	—	—	—	—	—
Interest rate - LIBOR	—	—	—	—	—	—
Contingent consideration	—	—	—	—	—	—
Net derivative liability positions	$ —	$ (178,361)	$ 35,861	$ (142,500)	$ —	$ (142,500)

	December 31, 2020					
(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 32,958	$ —	$ 32,958	$ (24,930)	$ 8,028
Commodity - NGL	—	2,720	—	2,720	(2,720)	—
Commodity - Natural gas	—	521	—	521	(656)	(135)
Contingent consideration	—	—	—	—	—	—
Noncurrent:						
Commodity - Oil	$ —	$ —	$ —	$ —	$ —	$ —
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	535	—	535	(535)	—
Contingent consideration	—	—	—	—	—	—
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (25,118)	$ —	$ (25,118)	$ 24,930	$ (188)
Commodity - NGL	—	(16,185)	—	(16,185)	2,720	(13,465)
Commodity - Natural gas	—	(17,958)	—	(17,958)	656	(17,302)
Interest rate - LIBOR	—	(206)	—	(206)	—	(206)
Contingent consideration	—	(665)	—	(665)	—	(665)
Noncurrent:						
Commodity - Oil	$ —	$ (10,932)	$ —	$ (10,932)	$ —	$ (10,932)
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	(1,476)	—	(1,476)	535	(941)
Interest rate - LIBOR	—	(63)	—	(63)	—	(63)
Contingent consideration	—	(115)	—	(115)	—	(115)
Net derivative liability positions	$ —	$ (35,984)	$ —	$ (35,984)	$ —	$ (35,984)

Commodity

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of commodity derivatives include each commodity derivative contract's corresponding commodity index price(s), forward price curve models for substantially similar instruments and counterparty risk-adjusted discount rates generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third party specialist's valuations of commodity derivatives, including the related inputs, and analyzed changes in fair values between reporting dates.

The Company's deferred premiums associated with its commodity derivative contracts were categorized as Level 3, as the Company utilized a net present value calculation to determine the valuation. They were considered to be measured on a recurring basis as the commodity derivative contracts they derive from were measured on a recurring basis. As commodity derivative contracts containing deferred premiums were entered into, the Company discounted the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (input rate), and then recorded the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the input rate of each deferred premium was not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would have resulted in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the initial valuation for the deferred premiums already recorded would have remained unaffected. While the Company believes the sources utilized to arrive at the fair value estimates were reliable, different sources or methods could have yielded different fair value estimates.

The following table summarizes the changes in net assets and liabilities for commodity derivatives classified as Level 3 measurements for the periods presented:

(in thousands)	Years ended December 31, 2021	2020	2019
Balance of Level 3 at beginning of year	$ —	$ (477)	$ (16,565)
Change in net present value of commodity derivative deferred premiums(1)	—	—	(139)
Settlements of commodity derivative deferred premiums(2)	—	477	16,227
Balance of Level 3 at end of year	$ —	$ —	$ (477)

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(1) These amounts are included in "Interest expense" on the consolidated statements of operations.

(2) The amount for the year ended December 31, 2019 includes $7.2 million that represents the present value of deferred premiums settled upon their early termination.

Interest rate

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of the interest rate derivative include the LIBOR interest rate forward curve and a counterparty risk-adjusted discount rate generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third-party specialist's valuation of the interest rate derivative, including the related inputs, and analyzed changes in fair values between reporting dates.

Contingent consideration

Significant Level 2 inputs for the option pricing model used in the fair value mark-to-market analysis of the contingent considerations include WTI NYMEX Futures price curves, implied volatility of futures contracts and the Company's credit risk-adjusted discount rate generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third-party specialist's valuations, including the related inputs, and analyzed changes in fair values between the acquisition closing dates and the reporting dates. The fair values of the contingent considerations were recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. At each quarterly reporting period prior to the end of the contingency periods, the Company remeasured the contingent considerations with the changes in fair value recognized in earnings.

The Working Interest Sale provided for potential contingent payments to be paid to the Company. The Sixth Street Contingent Consideration associated with the Working Interest Sale was categorized as Level 3, as the Company utilized its own cash flow projections along with a risk-adjusted discount rate generated by a third-party valuation specialist to determine the valuation. The Company reviewed the third-party specialist's valuation, including the related inputs, and analyzed changes in fair values between the divestiture closing date and the reporting dates. The fair value of the Sixth Street Contingent Consideration was recorded as part of the basis in the oil and natural gas properties divested and as a contingent consideration asset. At each quarterly reporting period prior to the end of the contingency period, the Company will remeasure the Sixth Street Contingent Consideration with the changes in fair value recognized in earnings.

The following table summarizes the changes in contingent consideration derivatives classified as Level 3 measurements for the periods presented:

(in thousands)	Years ended December 31, 2021	2020	2019
Balance of Level 3 at beginning of year	$ —	$ —	$ —
Sixth Street Contingent Consideration valuation as of Sixth Street Closing Date	33,832	—	—
Change in net present value of Sixth Street Contingent Consideration	2,029	—	—
Balance of Level 3 at end of year	$ 35,861	$ —	$ —

The Company's acquisition of oil and natural gas properties that closed on April 30, 2020 provided for potential contingent payments to be paid by the Company. During the year ended December 31, 2021, the maximum amount of the $1.2 million contingent consideration was distributed to the counterparty. The fair value of the contingent consideration derivative liability was determined to be $0.2 million as of the April 30, 2020 acquisition date, and $0.8 million as of December 31, 2020.

The Company's acquisition of oil and natural gas properties that closed on December 12, 2019 provided for a potential contingent payment to be paid by the Company. The fair value of the contingent consideration derivative liability was $6.2 million as of the December 12, 2019 acquisition date. As the provisions for this contingent payment were not met, no payment by the Company was required.

See Notes 4.a, 4.b and 4.d for further discussion of the Company's acquisitions and divestitures associated with the potential contingent consideration payments.

b. Fair value measurement on a nonrecurring basis

See Note 2.i for the Level 2 fair value hierarchy input assumptions used in estimating the NRV of inventory, which was used to determine the $1.6 million and $1.4 million impairment expense of inventory recorded during the years ended December 31, 2021 and 2020, respectively, pertaining to line-fill and other inventories. The Company recorded $0.3 million in impairment expense of inventory during the year ended December 31, 2019, pertaining to line-fill.

See Note 4.d for the Level 3 fair value hierarchy input assumptions used in estimating the fair values of assets acquired and liabilities assumed for the acquisition of oil and natural gas properties accounted for as a business combination during the year ended December 31, 2019. There were no acquisitions accounted for as business combinations during the years ended December 31, 2021 or 2020.

Impairments are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. The Company recorded $8.2 million in impairment expense of long-lived assets during the years ended December 31, 2020, pertaining to midstream service assets. There were no long-lived asset impairments recorded during the years ended December 31, 2021 or 2019.

c. Items not accounted for at fair value

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values.

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amounts and fair values of the Company's debt as of the dates presented:

	December 31, 2021		December 31, 2020	
(in thousands)	**Long-term debt**	**Fair value(1)**	**Long-term debt**	**Fair value(1)**
January 2025 Notes	$ 577,913	$ 589,471	$ 577,913	$ 499,299
January 2028 Notes	361,044	378,578	361,044	299,667
July 2029 Notes	400,000	390,000	—	—
Senior Secured Credit Facility	105,000	105,040	255,000	255,187
Total	$ 1,443,957	$ 1,463,089	$ 1,193,957	$ 1,054,153

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(1) The fair values of the outstanding notes were determined using the Level 1 fair value hierarchy quoted market prices for each respective instrument as of December 31, 2021 and 2020. The fair values of the outstanding debt under the Senior Secured Credit Facility were estimated utilizing the Level 2 fair value hierarchy pricing model for similar instruments as of December 31, 2021 and 2020.

Note 12 Net income (loss) per common share

Basic and diluted net income (loss) per common share are computed by dividing net income (loss) by the weighted-average common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution of non-vested restricted stock awards, outstanding stock option awards, non-vested performance share awards and the non-vested outperformance share award. See Note 9.a for additional discussion of these awards. For the year ended December 31, 2021, the dilutive effects of these awards were calculated utilizing the treasury stock method. For the years ended December 31, 2020 and 2019, all of these awards were anti-dilutive due to the Company's net loss and, therefore, were excluded from the calculation of diluted net loss per common share.

The following table reflects the calculations of basic and diluted (i) weighted-average common shares outstanding and (ii) net income (loss) per common share for the periods presented:

	Years ended December 31,		
(in thousands, except for per share data)	2021	2020	2019
Net income (loss) (numerator)	$ 145,008	$ (874,173)	$ (342,459)
Weighted-average common shares outstanding (denominator)[(1)]:			
Basic	14,240	11,668	11,565
Dilutive non-vested restricted stock awards	181	—	—
Dilutive non-vested performance share awards[(2)]	43	—	—
Diluted	14,464	11,668	11,565
Net income (loss) per common share[(1)]:			
Basic	$ 10.18	$ (74.92)	$ (29.61)
Diluted	$ 10.03	$ (74.92)	$ (29.61)

(1) For the year ended December 31, 2021, the weighted-average common shares outstanding used in the computation of basic and diluted net income per share includes the effects of equity issued by the Company during the year. There was no comparable equity issued during the years ended December 31, 2020 and 2019. See Notes 4.a and 8.a for additional discussion of equity issued by the Company.

(2) The dilutive effect of the non-vested performance shares for the year ended December 31, 2021 was calculated as of the end of the performance period on December 31, 2021.

Note 13 Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The following table presents the "Current" and "Deferred" income tax (expense) benefit reported on the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Current income tax (expense) benefit:			
Federal	$ —	$ —	$ —
State	(1,324)	—	—
Deferred income tax (expense) benefit:			
Federal	—	—	—
State	(2,321)	3,946	2,588
Total income tax (expense) benefit	$ (3,645)	$ 3,946	$ 2,588

The deferred income tax (expense) benefit affects the net deferred tax (liability) asset. See below for the table of significant components of the Company's net deferred tax (liability) asset as of December 31, 2021, 2020 and 2019.

Total income tax (expense) benefit differed from amounts computed by applying the applicable federal income tax rate of 21% for the years ended December 31, 2021, 2020 and 2019 to pre-tax earnings as a result of the following:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Income tax (expense) benefit computed by applying the statutory rate	$ (31,217)	$ 184,405	$ 72,460
Change in deferred tax valuation allowance	45,717	(182,634)	(69,316)
Non-deductible equity-based compensation	(13,640)	—	—
State income tax and change in valuation allowance	(3,274)	2,903	1,863
Other items	(1,231)	(728)	(2,419)
Total income tax (expense) benefit	$ (3,645)	$ 3,946	$ 2,588

The effective tax rate was not meaningful for the periods presented. The Company's effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year.

The Company is required to estimate the federal and state income taxes in each of the jurisdictions it operates in. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items for tax and financial accounting purposes. These differences and the Company's net operating loss carryforwards result in deferred tax assets and liabilities.

The following table presents significant components of the Company's net deferred tax (liability) asset as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Net operating loss carryforward	$ 445,426	$ 444,031
Oil and natural gas properties, midstream service assets and other fixed assets	(39,504)	22,231
Equity-based compensation	11,123	22,494
Derivatives	36,639	7,166
Loss on sale of assets	(14,364)	(8,458)
Other	3,227	3,130
Net deferred tax asset before valuation allowance	442,547	490,594
Valuation allowance	(443,390)	(489,116)
Texas net deferred tax (liability) asset[(1)]	$ (843)	$ 1,478

(1) The net deferred tax (liability) asset is included in "Other noncurrent liabilities" and "Other noncurrent assets, net" as of December 31, 2021 and 2020, respectively.

The following table presents the Company's federal net operating loss carryforwards and their applicable expiration dates as of the date presented:

(in thousands)	December 31, 2021
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,284,150
Total expiring federal net operating loss carryforwards	1,737,098
Non-expiring federal net operating loss carryforwards	376,212
Total federal net operating loss carryforwards	$ 2,113,310

The Company had federal net operating loss carryforwards totaling $2.1 billion and state of Oklahoma net operating loss carryforwards totaling $34.6 million as of December 31, 2021, which begin expiring in 2026 and 2032, respectively. Due to the passing of the Tax Act (defined below), $376.2 million of the federal net operating loss carryforwards will not expire but may be limited in future periods. If the Company were to experience an "ownership change" as determined under Section 382 of the Internal Revenue Code, the Company's ability to offset taxable income arising after the ownership change with net operating losses arising prior to the ownership change would be limited. Mainly as a result of the estimated tax gain arising from the Working Interest Sale that occurred during the year ended December 31, 2021, the Company has recorded a corresponding current tax expense of $1.3 million for Texas franchise tax.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. To the extent a valuation allowance is established or is increased or decreased during a period, there is a corresponding expense or reduction of expense within the tax provision in the consolidated statement of operations.

During the years ended December 31, 2021 and 2020, in evaluating whether it was more likely than not that the Company's net deferred tax assets were realizable through future net income, the Company considered all available positive and negative evidence, including (i) its earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition, (ii) its ability to recover net operating loss carryforward deferred tax assets in future years, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) its ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs in order to prevent an operating loss carryforward from expiring unused and future projections of taxable income, (v) its current price protection utilizing oil, NGL and natural gas hedges, (vi) future revenue and operating cost projections that indicate it will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures and (vii) current market prices for oil, NGL and natural gas. Based on all the evidence available, the Company determined it was more likely than not that the net deferred tax assets were not realizable. As of December 31, 2021, a total valuation allowance of $443.4 million has been recorded to offset the Company's federal and Oklahoma net deferred tax assets resulting in a Texas net deferred tax liability of $0.8 million that is included in "Other noncurrent liabilities, net" on the consolidated balance sheets.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). With the passage of the Tax Act, the Alternative Minimum Tax ("AMT") on corporations was repealed and a provision was added allowing corporations to offset future tax liabilities by the amount of AMT paid with an AMT credit carryforward. The Coronavirus Aid, Relief, and Economic Security Act, enacted March 27, 2020 ("CARES Act"), modified the opportunity for corporations to receive the AMT carryover refunds by adding in a provision where the AMT credit carryforwards do not expire and are fully refundable with the filing of the Company's 2019 consolidated tax return. The Company paid AMT during the year ended December 31, 2017, creating an AMT credit carryforward in the amount of $4.1 million, of which $2.0 million was received during the year ended December 31, 2019 and the remaining $2.1 million was received during the year ended December 31, 2020.

The Company files a single return. The Company's income tax returns for the years 2018 through 2021 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has operations. Additionally, the statute of limitations for examination of federal net operating loss carryforwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.q for the Company's significant accounting policies for income taxes.

Note 14 Credit risk

Financial instruments that potentially subject the Company to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivatives. The Company places its cash and cash equivalents with high credit quality financial institutions. The Company uses commodity and interest rate derivatives to hedge its exposure to commodity prices and interest rate volatility, respectively. These transactions expose the Company to potential credit risk from its counterparties. The Company has entered into International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of its commodity and interest rate derivative counterparties, each of whom is also a lender in its Senior Secured Credit Facility, which, together with hedge agreements with lenders under such facility, is secured by its oil, NGL and natural gas reserves; therefore, the Company is not required to post any additional collateral. The Company did not require collateral from its commodity and interest rate derivative counterparties. The terms of the ISDA Agreements provide the non-defaulting or non-affected party the right to terminate the agreement upon the occurrence of certain events of default and termination events by a party and also provide for the marking to market of outstanding positions and the offset of the mark to market amounts owed to and by the parties (and in certain cases, the affiliates of the non-defaulting or non-affected party) upon termination; therefore, the credit risk associated with its commodity and interest rate derivative counterparties is somewhat mitigated. The Company minimizes the credit risk in commodity and interest rate derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into commodity and interest rate derivatives only with counterparties that meet its minimum credit quality standard or have a guarantee from an affiliate that meets its minimum credit quality standard and (iii) monitoring the creditworthiness of its counterparties on an ongoing basis. As of December 31, 2021, the Company had a net liability of $178.4 million from the fair values of its open commodity and interest rate derivative contracts. See "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" located elsewhere in this Annual Report and Notes 2.e, 10, 11.a and 18.b for additional information regarding the Company's derivatives.

The Company typically sells production to a relatively limited number of customers, as is customary in the exploration, development and production business. The Company's sales of purchased oil are generally made to a few customers. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the oil and natural gas properties operated by the Company.

The majority of the Company's accounts receivable are unsecured. On occasion the Company requires its customers to post collateral, and the inability or failure of the Company's significant customers to meet their obligations to the Company or their insolvency or liquidation may adversely affect the Company's financial results. In the current market environment, the Company believes that it could sell its production to numerous companies, so that the loss of any one of its major purchasers would not have a material adverse effect on its financial condition and results of operations solely by reason of such loss. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. See Notes 2.d and 2.n for additional information regarding the Company's accounts receivable and revenue recognition, respectively.

The following table presents purchasers that individually accounted for 10% or more of the Company's oil, NGL and natural gas sales in at least one of the years presented:

	Years ended December 31,		
	2021	2020	2019
Purchaser A[1]	29 %	33 %	59 %
Purchaser B	24 %	24 %	18 %
Purchaser C[1]	17 %	14 %	n/a[2]
Purchaser D	n/a[2]	10 %	n/a[2]
Purchaser E	n/a[2]	n/a[2]	15 %
Purchaser F[1]	14 %	n/a[2]	n/a[2]

(1) This purchaser of the Company's oil, NGL and natural gas sales is also a purchaser of the Company's sales of purchased oil included in the table below.

(2) This purchaser did not account for 10% or greater of the Company's oil, NGL and natural gas sales.

The following table presents purchasers that individually accounted for 10% or more of the Company's sales of purchased oil in at least one of the years presented:

	Years ended December 31,		
	2021	2020	2019
Purchaser A(1)	47 %	69 %	26 %
Purchaser B(1)	31 %	16 %	70 %
Purchaser C(1)	22 %	14 %	n/a(2)

(1) This purchaser of the Company's sales of purchased oil is also a purchaser of the Company's oil, NGL and natural gas sales included in the table above.

(2) This purchaser did not account for 10% or greater of the Company's sales of purchased oil.

Note 15 Commitments and contingencies

a. Litigation

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity. During the year ended December 31, 2019, the Company finalized and received a favorable settlement of $42.5 million in connection with the Company's damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. This settlement is recorded as "Litigation settlement" on the consolidated statement of operations. The Company does not anticipate receiving further payments in connection with this matter as this settlement constituted a full and final satisfaction of the Company's claims.

b. Drilling rig contracts

The Company enters into drilling rig contracts to ensure availability of desired rigs to facilitate drilling plans. The Company has two operating leases for terms of multiple months, both of which contain early termination clauses that require the Company to potentially pay penalties to the third parties should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for the years ended December 31, 2021, 2020 or 2019. As these drilling rig contracts are operating leases with an initial term greater than 12 months, the present value of the future commitment as of December 31, 2021 is included in current and noncurrent "Operating lease liabilities" on the consolidated balance sheet as of December 31, 2021. See Note 5 for additional discussion of the Company's leases.

c. Firm sale and transportation commitments

The Company has committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for the Company's business. In certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. A portion of the Company's commitments are related to transportation commitments with a certain pipeline pertaining to the gathering of the Company's production from established acreage that extends into 2024. The Company was unable to satisfy a portion of this particular commitment with produced or purchased oil. Therefore, the Company expensed firm transportation payments on excess capacity of $4.4 million and $4.0 million during the years ended December 31, 2021 and 2020, respectively, which is recorded in "Transportation and marketing expenses" on the consolidated statements of operations. The Company had an estimated aggregate liability of firm transportation payments on excess capacity of $4.7 million and $3.5 million as of December 31, 2021 and 2020, respectively, and is included in "Accounts payable and accrued liabilities" on the consolidated balance sheets. The Company expensed other contractual penalties related to sales commitments of $0.9 million during the year ended December 31, 2019, which is recorded net with oil, NGL, and natural gas sales revenues on the consolidated statement of operations. As of December 31, 2021, future firm sale and transportation commitments of $213.3 million are expected to be satisfied and, as such, are not recorded as a liability on the consolidated balance sheet.

d. Sand commitment

During the year ended December 31, 2021, the Company renegotiated an agreement to take delivery of processed sand at a fixed price for one year, which is utilized in the Company's completions activities, from its sand mine that is operated by a third-party contractor. As of December 31, 2021, under the terms of this agreement, the Company is required to purchase a certain volume remaining under its commitment or it would incur a shortfall payment of $5.3 million at the end of the contract period.

e. Federal and state regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable federal and state regulations related to oil and natural gas exploration and production, and that compliance with the current regulations will not have a material adverse impact on the financial position or results of operations of the Company. These rules and regulations are frequently amended or reinterpreted; therefore, the Company is unable to predict the future cost or impact of complying with these regulations.

f. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of December 31, 2021 or 2020.

Note 16 Related parties

a. Halliburton

Beginning in 2020, the Chairman of the Company's board of directors is on the board of directors of Halliburton Company ("Halliburton"). Halliburton provides drilling and completions services to the Company.

The following table presents the capital expenditures for oil and natural gas properties paid to Halliburton included in the consolidated statements of cash flows for the periods presented:

	Years ended December 31,	
(in thousands)	**2021**	**2020**
Capital expenditures for oil and natural gas properties	$ 69,670	$ 63,886

Note 17 Organizational restructurings

On June 29, 2021 (the "Effective Date"), the Company committed to a company-wide reorganization effort (the “Plan”) that included a workforce reduction of 14 individuals, or approximately 5% of the workforce. The reduction in workforce was communicated to employees on the Effective Date and implemented immediately, subject to certain administrative procedures. The Plan was put in place in order to better position the Company for the future.

On June 17, 2020, the Company announced organizational changes, including a workforce reduction of 22 individuals which included a senior officer, that were implemented immediately, subject to certain administrative procedures. The Company's board of directors approved the reduction in workforce in response to the COVID-19 pandemic and market conditions to reduce costs and better position the Company for the future.

On September 27, 2019, in connection with the previously announced comprehensive succession planning process, the Company announced that, effective as of October 1, 2019, Randy A. Foutch would transition from his role as Chief Executive Officer. In connection with this transition and in recognition of his efforts as the Company's founder, Mr. Foutch entered into an agreement under which he received the following payments and benefits: (i) a "Founder's Bonus" of $5.9 million approved by the board of directors and (ii) 18 months of COBRA employer contributions that began on October 1, 2019.

On April 2, 2019, the Company announced the retirement of two of its senior officers. Additionally, on April 8, 2019, the Company committed to a company-wide reorganization effort that included a workforce reduction of 20%, which included an executive officer. The reduction in workforce was communicated to employees on April 8, 2019 and implemented immediately, subject to certain administrative procedures. The Company's board of directors approved the reduction in workforce in response to market conditions and to reduce costs and better position the Company for the future.

In connection with these organizational restructurings, the Company incurred charges comprised of compensation, tax, professional, outplacement and insurance-related expenses. The following table reflects the aggregate of these expenses, which is recorded as "Organizational restructuring expenses" on the consolidated statements of operations, for the periods presented:

	Years ended December 31,		
(in thousands)	**2021**	**2020**	**2019**
Organizational restructuring expenses	$ 9,800	$ 4,200	$ 16,371

All equity-based compensation awards held by the affected employees were forfeited and the corresponding equity-based compensation was reversed. See Note 9.a for additional information on the associated forfeiture activity for the years ended December 31, 2021, 2020 and 2019. The following table reflects the aggregate of gross equity-based compensation expense reversals in connection with the Company's respective organizational restructurings, which is recorded in "General and administrative" on the consolidated statements of operations, for the periods presented:

	Years ended December 31,		
(in thousands)	**2021**	**2020**	**2019**
Gross equity-based compensation expense reversals	$ (1,088)	$ (793)	$ (11,706)

Note 18 Subsequent events

a. Senior Secured Credit Facility

On January 14, 2022, the Company borrowed an additional $50.0 million and on January 31, 2022, the Company repaid $10.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $145.0 million as of February 21, 2022.

b. Commodity derivatives

The following table summarizes the resulting open oil derivative positions as of December 31, 2021, updated for the derivative transactions entered into from December 31, 2021 through February 24, 2022, for the settlement periods presented:

	Year 2022	Year 2023
Oil:		
WTI NYMEX - Swaps:		
Volume (Bbl)	1,878,000	—
Weighted-average price ($/Bbl)	$ 76.11	$ —
WTI NYMEX - Collars:		
Volume (Bbl)	3,394,500	3,632,000
Weighted-average floor price ($/Bbl)	$ 58.23	$ 65.50
Weighted-average ceiling price ($/Bbl)	$ 69.39	$ 79.94
Total WTI NYMEX:		
Total volume (Bbl)	5,272,500	3,632,000
Weighted-average floor price ($/Bbl)	$ 64.60	$ 65.50
Weighted-average ceiling price ($/Bbl)	$ 71.78	$ 79.94
Brent ICE - Swaps:		
Volume (Bbl)	4,124,500	—
Weighted-average price ($/Bbl)	$ 48.34	$ —
Brent ICE - Collars:		
Volume (Bbl)	1,551,250	—
Weighted-average floor price ($/Bbl)	$ 56.65	$ —
Weighted-average ceiling price ($/Bbl)	$ 65.44	$ —
Total Brent ICE:		
Total volume with floor (Bbl)	5,675,750	—
Weighted-average floor price ($/Bbl)	$ 50.61	$ —
Weighted-average ceiling price ($/Bbl)	$ 53.01	$ —

See Note 10.a for additional discussion regarding the Company's derivatives. There has been no other derivative activity subsequent to December 31, 2021.

Note 19 Supplemental oil, NGL and natural gas disclosures (unaudited)

a. Incurred capital expenditures in oil and natural gas property acquisition, exploration and development activities

The following table presents incurred capital expenditures in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Property acquisition costs:			
Evaluated	$ 899,128	$ 11,368	$ 126,372
Unevaluated	198,770	25,549	83,738
Exploration costs	33,482	17,337	19,954
Development costs	410,855	326,823	450,501
Total oil and natural gas properties incurred capital expenditures	$ 1,542,235	$ 381,077	$ 680,565

b. Aggregate capitalized oil, NGL and natural gas costs

The following table presents the aggregate capitalized costs related to oil, NGL and natural gas production activities with applicable accumulated depletion and impairment as of the dates presented:

(in thousands)	December 31, 2021	December 31, 2020
Gross capitalized costs:		
Evaluated properties	$ 8,968,668	$ 7,874,932
Unevaluated properties not being depleted	170,033	70,020
Total gross capitalized costs	9,138,701	7,944,952
Less accumulated depletion and impairment	(7,019,670)	(6,817,949)
Net capitalized costs	$ 2,119,031	$ 1,127,003

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2021, by year in which such costs were incurred:

(in thousands)	2021	2020	2019	2018 and prior	Total
Unevaluated properties not being depleted	$ 166,158	$ 784	$ 1,902	$ 1,189	$ 170,033

Unevaluated properties, which are not subject to depletion, are not individually significant and consist of costs for acquiring oil and natural gas leasehold where no evaluated reserves have been identified, including costs of wells being evaluated. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the depletion calculation.

c. Results of operations of oil, NGL and natural gas producing activities

The following table presents the results of operations of oil, NGL and natural gas producing activities (excluding corporate overhead and interest costs) for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Revenues:			
Oil, NGL and natural gas sales	$ 1,147,143	$ 496,355	$ 706,548
Production costs:			
Lease operating expenses	101,994	82,020	90,786
Production and ad valorem taxes	68,742	33,050	40,712
Transportation and marketing expenses	47,916	49,927	25,397
Total production costs	218,652	164,997	156,895
Other costs:			
Depletion	201,691	203,492	250,857
Accretion of asset retirement obligation	4,018	4,227	3,926
Impairment expense	—	889,453	620,565
Income tax expense (benefit)(1)	14,456	—	(3,257)
Total other costs	220,165	1,097,172	872,091
Results of operations	$ 708,326	$ (765,814)	$ (322,438)

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(1) During each of the years ended December 31, 2021, 2020 and 2019, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, the income tax expense (benefit) was computed utilizing the Company's effective tax rate of 2% for the year ended December 31, 2021, 0% for the year ended December 31, 2020 and 1% for the year ended December 31, 2019, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's "Total income tax (expense) benefit" on the consolidated statements of operations.

d. Net proved oil, NGL and natural gas reserves

Ryder Scott Company, L.P. ("Ryder Scott"), the Company's independent reserve engineers, estimated 100% of the Company's proved reserves as of December 31, 2021, 2020 and 2019. In accordance with SEC regulations, the reserves as of December 31, 2021, 2020 and 2019 were estimated using the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point. See Note 6.a for these Realized Prices. The Company's reserves are reported in three streams: oil, NGL and natural gas.

The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

The following tables provide an analysis of the changes in estimated proved reserve quantities of oil, NGL and natural gas for the years ended December 31, 2021, 2020 and 2019, all of which are located within the U.S.:

	Year ended December 31, 2021			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	67,759	100,922	657,284	278,228
Revisions of previous estimates	4,740	16,952	102,080	38,709
Extensions, discoveries and other additions	10,354	5,269	22,479	19,369
Acquisitions of reserves in place	65,572	19,711	90,023	100,286
Divestitures of reserves in place	(15,904)	(34,129)	(228,546)	(88,125)
Production	(11,619)	(8,678)	(57,175)	(29,827)
End of year	120,902	100,047	586,145	318,640
Proved developed reserves:				
Beginning of year	51,751	96,251	633,503	253,586
End of year	70,727	78,908	494,476	232,048
Proved undeveloped reserves:				
Beginning of year	16,008	4,671	23,781	24,642
End of year	50,175	21,139	91,669	86,592

	Year ended December 31, 2020			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	78,639	102,198	675,237	293,377
Revisions of previous estimates	(10,517)	6,218	34,376	1,430
Extensions, discoveries and other additions	4,282	1,811	10,772	7,888
Acquisitions of reserves in place	5,182	1,310	6,948	7,650
Production	(9,827)	(10,615)	(70,049)	(32,117)
End of year	67,759	100,922	657,284	278,228
Proved developed reserves:				
Beginning of year	52,711	90,861	600,334	243,628
End of year	51,751	96,251	633,503	253,586
Proved undeveloped reserves:				
Beginning of year	25,928	11,337	74,903	49,749
End of year	16,008	4,671	23,781	24,642

	Year ended December 31, 2019			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	61,894	86,647	537,756	238,167
Revisions of previous estimates	(7,865)	5,301	69,678	9,049
Extensions, discoveries and other additions	13,573	12,614	83,345	40,078
Acquisitions of reserves in place	21,413	6,754	44,627	35,605
Production	(10,376)	(9,118)	(60,169)	(29,522)
End of year	78,639	102,198	675,237	293,377
Proved developed reserves:				
Beginning of year	55,893	79,241	491,828	217,105
End of year	52,711	90,861	600,334	243,628
Proved undeveloped reserves:				
Beginning of year	6,001	7,406	45,928	21,062
End of year	25,928	11,337	74,903	49,749

The following discussion is for the year ended December 31, 2021. The Company's positive revision of 38,709 MBOE of previously estimated quantities consisted of (i) 3,622 MBOE of negative revisions from performance of proved developed producing wells, (ii) 2,885 MBOE of negative revisions from a decrease in previously estimated quantities of proved undeveloped locations, (iii) 37,341 MBOE of positive revisions from an increase in the Realized Prices for oil, NGL and natural gas and other changes to proved wells and (iv) 7,875 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. Six of these locations became proved developed producing wells in 2021 and twelve were revised back to proved undeveloped reserves as they are now economically producible due to increased commodity prices and increases in lateral lengths. Extensions, discoveries and other additions of 19,369 MBOE consisted of (i) 6,724 MBOE that resulted from new wells drilled and (ii) 12,645 MBOE that resulted from new horizontal proved undeveloped locations added in the Company's acreage in Howard and western Glasscock Counties. Sales of reserves of 88,125 MBOE attributed to the divestment of 37.5% interest of certain proved developed producing wells in Reagan and Glasscock counties. Acquisitions of reserves in place of 100,286 MBOE consisted of (i) 47,310 MBOE from new proved developed wells (ii) 52,976 MBOE from new proved undeveloped locations in Howard and western Glasscock Counties.

The following discussion is for the year ended December 31, 2020. The Company's positive revision of 1,430 MBOE of previously estimated quantities consisted of (i) 29,080 MBOE of positive revisions from performance of proved developed producing wells, (ii) 3,140 MBOE of negative revisions from a decrease in previously estimated quantities of proved undeveloped locations, (iii) 8,245 MBOE of negative revisions due to proved undeveloped locations that were removed due to year-end pricing and (iv) 16,265 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved wells. Extensions, discoveries and other additions of 7,888 MBOE consisted of (i) 5,347 MBOE that resulted from new wells drilled and (ii) 2,541 MBOE that resulted from new horizontal proved undeveloped locations added in the Company's Howard County, Texas acreage. Acquisitions of reserves in place of 7,650 MBOE consisted of (i) 367 MBOE from new proved developed producing wells and (ii) 4,016 MBOE from additional acreage acquired under proved locations in Howard County and (iii) 3,267 MBOE from new proved undeveloped locations in Howard County.

The following discussion is for the year ended December 31, 2019. The Company's positive revision of 9,049 MBOE of previously estimated quantities consisted of (i) 20,858 MBOE of positive revisions from performance of proved developed producing wells, (ii) 12,417 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved developed producing wells and (iii) 608 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. Extensions, discoveries and other additions of 40,078 MBOE consisted of (i) 24,629 MBOE that resulted from new wells drilled and (ii) 15,449 MBOE that resulted from new horizontal proved undeveloped locations added in our established acreage. Acquisitions of reserves in place of 35,605 MBOE consisted of (i) 1,306 MBOE from new proved developed producing wells and (ii) 34,299 MBOE from 86 new proved undeveloped locations in Howard and western Glasscock Counties of Texas.

e. Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil, NGL and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of proved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2021, 2020 and 2019 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point. All Realized Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net cash flows. Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling for each of the quarterly periods in 2020 and for the third and fourth quarters of 2019 and, as such, the Company recorded non-cash full cost ceiling impairments totaling $889.5 million and $620.6 million during the years ended December 31, 2020 and 2019, respectively. No full cost ceiling impairment was recorded for the year ended December 31, 2021. See Note 6.a for discussion of the Benchmark Prices, Realized Prices and the 2020 and 2019 full cost ceiling impairments recorded.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Future cash inflows	$ 11,846,148	$ 3,824,104	$ 5,702,580
Future production costs	(3,595,524)	(1,740,537)	(1,994,732)
Future development costs	(1,064,527)	(351,568)	(615,839)
Future income tax expenses	(774,461)	(20,076)	(24,392)
Future net cash flows	6,411,636	1,711,923	3,067,617
10% discount for estimated timing of cash flows	(2,986,324)	(697,069)	(1,405,356)
Standardized measure of discounted future net cash flows	$ 3,425,312	$ 1,014,854	$ 1,662,261

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, prices and costs as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following table presents the changes in the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves for the periods presented:

	Years ended December 31,		
(in thousands)	2021	2020	2019
Standardized measure of discounted future net cash flows, beginning of year	$ 1,014,854	$ 1,662,261	$ 2,114,237
Changes in the year resulting from:			
Sales, less production costs	(934,440)	(331,358)	(549,653)
Revisions of previous quantity estimates	426,060	199	36,182
Extensions, discoveries and other additions	293,511	60,004	361,479
Net change in prices and production costs	1,572,662	(770,885)	(900,019)
Changes in estimated future development costs	134,091	64,146	14,876
Previously estimated development incurred capital expenditures during the period	169,376	186,261	158,631
Acquisitions of reserves in place	1,509,087	14,208	207,636
Divestitures of reserves in place	(369,601)	—	—
Accretion of discount	102,607	167,227	217,119
Net change in income taxes	(279,722)	(1,205)	46,939
Timing differences and other	(213,173)	(36,004)	(45,166)
Standardized measure of discounted future net cash flows, end of year	$ 3,425,312	$ 1,014,854	$ 1,662,261

Estimates of economically recoverable oil, NGL and natural gas reserves and of future net cash flows are based upon a number of variable factors and assumptions, all of which are, to some degree, subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil, NGL and natural gas may differ materially from the amounts estimated.

Note 20 Supplemental quarterly financial data (unaudited)

The below quarterly financial data is being provided in consideration of the Company's 1-for-20 reverse stock split effective June 1, 2020, and the associated material retrospective adjustment to first-quarter 2020 basic and diluted net income per common share. The Company's results by quarter for the periods presented are as follows:

	December 31, 2021			
(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 250,230	$ 294,371	$ 379,250	$ 470,224
Operating income	$ 102,803	$ 108,347	$ 265,736	$ 243,449
Net income (loss)	$ (75,439)	$ (132,661)	$ 136,832	$ 216,276
Net income (loss) per common share:				
Basic	$ (6.33)	$ (10.47)	$ 8.68	$ 13.07
Diluted	$ (6.33)	$ (10.47)	$ 8.56	$ 12.84

	December 31, 2020			
(in thousands, except per share data)	First Quarter(1)	Second Quarter(1)	Third Quarter(1)	Fourth Quarter(1)
Revenues	$ 204,992	$ 110,588	$ 173,547	$ 188,065
Operating loss	$ (181,972)	$ (434,052)	$ (167,678)	$ (78,031)
Net income (loss)	$ 74,646	$ (545,455)	$ (237,432)	$ (165,932)
Net income (loss) per common share(2):				
Basic	$ 6.43	$ (46.75)	$ (20.32)	$ (14.18)
Diluted	$ 6.39	$ (46.75)	$ (20.32)	$ (14.18)

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(1) See Note 6.a for discussion of the Company's full cost ceiling impairments recorded during the year ended December 31, 2020.

(2) Per share data was retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.b.

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of the common stock, $0.01 par value per share ("Common Stock"), of Laredo Petroleum, Inc., a Delaware corporation (the "Company," "we," "us," and "our"), which is the only class of our securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following summary is not complete. You should refer to the applicable provisions of our amended and restated certificate of incorporation (the "Charter"), our second amended and restated bylaws, as amended (the "Bylaws"), and the General Corporation Law of the State of Delaware ("DGCL") for a complete statement of the terms and rights of the Common Stock. Copies of the Charter and Bylaws have been filed with the Securities and Exchange Commission as exhibits 3.1 and 3.3, respectively, to the Company's Annual Report on Form 10-K.

Authorized Capital Stock

Under our Charter, our authorized capital stock consists of 22,500,000 shares of Common Stock and 50,000,000 shares of preferred stock, par value $0.01 per share ("Preferred Stock").

Common Stock

Voting Rights

Except as provided by law or in a Preferred Stock designation, holders of Common Stock ("stockholders") are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, stockholders are not entitled to vote on any amendment to the Charter (including any certificate of designations relating to any series of Preferred Stock) that relates solely to the terms of any outstanding series of Preferred Stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the Charter (including any certificate of designations relating to any series of Preferred Stock) or pursuant to the DGCL.

Dividend Rights

Subject to preferences that may be applicable to any outstanding shares or series of Preferred Stock and restrictions in the Company debt agreements, stockholders are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors (the "Board of Directors") out of funds legally available for dividend payments.

Rights Upon Liquidation

In the event of any liquidation, dissolution or winding-up of our affairs, stockholders will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of Preferred Stock, if any.

Fully Paid and Non-assessable

Our issued and outstanding shares of Common Stock are fully paid and non-assessable.

No Preemptive, Redemption or Conversion Rights

Stockholders have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the Common Stock.

Preferred Stock

Our Charter authorizes our Board of Directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of Preferred Stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of Preferred Stock. Each class or series of Preferred Stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by our Board of Directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights.

Listing

Our Common Stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI."

Transfer Agent and Registrar

The transfer agent and registrar for our Common Stock is American Stock Transfer & Trust Company, LLC.

Anti-Takeover Effects of Provisions of our Charter, Bylaws and Delaware Law

Some provisions of Delaware law, and our Charter and Bylaws described below, contain provisions that may be deemed to have an anti-takeover effect. Such provisions could make the following transactions more difficult: (i) acquisition of us by means of a tender offer, a proxy contest or otherwise and (ii) removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could delay, make it more difficult to accomplish or deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for shares of our Common Stock.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Advance Notice of Stockholder Proposals and Nominations

Our Bylaws provide for advance notice procedures with regard to stockholder nomination of candidates for election as directors or proposals of business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder nominations or proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 45 days nor more than 75 days prior to the first anniversary date of the date on which we first mailed our proxy materials for the annual meeting for the preceding year. Our Bylaws specify the requirements as to form and content of all stockholders' notices.

Issuance of Preferred Stock

Our Charter authorizes the Board of Directors with the ability to establish the terms of undesignated Preferred Stock. This ability makes it possible for our Board of Directors to issue, without stockholder approval, Preferred Stock with voting or other rights or preferences that could impede the success of any attempt to change control of us.

Issuance of Rights

The Board of Directors is expressly authorized to cause the Company to issue, whether or not in connection with the issue and sale of any shares of Common Stock, rights to enter into any agreements necessary or convenient for such issuance, and to enter into other agreements necessary and convenient to the conduct of the business of the Company.

Control of Board of Directors

Our Board of Directors is divided into three classes with each class serving staggered three year terms, and the authorized number of directors may be changed only by resolution of the Board of Directors without consent of the stockholders. Additionally, all vacancies, including newly created directorships, shall, except as otherwise required by law or by resolution of the Board of Directors and subject to the rights of the holders of any series of Preferred Stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum. Subject to the rights of the holders of any series of Preferred Stock, a director may only be removed from office “for cause” by the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock.

Meeting Requirement

Any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of Preferred Stock.

Supermajority Approval Requirements

Certain provisions of our Charter may be amended only with the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock. Our Bylaws may be amended by the affirmative vote of the stockholders of at least 75% of our then outstanding Common Stock or our Board of Directors.

Special Meetings of Stockholders

Our Bylaws provide that a special meeting of stockholders may only be called by the Board of Directors.

Corporate Opportunity

Our Charter provides that we renounce our (and our subsidiaries’) ability to engage in any business opportunity, transaction or other matter in which Warburg Pincus LLC (“Warburg Pincus”) or any private fund that it manages or advises, any of their officers, directors, partners, employees, and any portfolio company in which such entities or persons have an equity interest (other than us and our subsidiaries) (each a “specified party”) participates or desires or seeks to participate in and that involves any aspect of the energy business or industry, unless any such business opportunity, transaction or matter is offered in writing solely to (i) one of our directors or officers who is not also a specified party or (ii) a specified party who is one of our directors, officers or employees and is offered such opportunity solely in his or her capacity as one of our directors, officers or employees.

Forum Selection Clause

Under our Charter, unless we consent in writing to the selection of an alternative forum, 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 stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL or (iv) any action asserting a claim governed by the internal affairs doctrine.

Section 203 of the DGCL

We are subject to the provisions of Section 203 of the DGCL, which regulates corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the business combination or transaction in which the person became interested is approved by the board of directors before the date the interested stockholder attained that status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced other than, for purposes of determining the voting stock outstanding (but not the outstanding stock owned by the interested stockholder), shares owned by persons who are directors and also officers of us and by certain employee stock plans; or

- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

In general, Section 203 defines a “business combination” to include the following:

- certain mergers or consolidations involving the corporation and the interested stockholder;

- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation to or with the interested stockholder;

- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;

- subject to certain exceptions, any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or

- the receipt by the interested stockholder of the benefit of loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons. Affiliates of Warburg Pincus owned their equity in us at the time we completed our corporate reorganization in December 2011 in connection with our initial public offering, and, therefore, Warburg Pincus is not subject to the restrictions of Section 203.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 24, 2022, with respect to the consolidated financial statements, and internal control over financial reporting included in the Annual Report of Laredo Petroleum, Inc. 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 Laredo Petroleum, Inc. on Form S-3 (File No. 333-230427, File No. 333-257799 and File No. 333-260479) and on Forms S-8 (File No. 333-178828, File No. 333-211610, File No. 333-231593 and File No. 333-256431).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 24, 2022

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the references to its firm in the form and context in which they appear in this Annual Report on Form 10-K filed by Laredo Petroleum, Inc. (the “Annual Report”). Ryder Scott Company, L.P. hereby further consents to the use and incorporation by reference of information from its reports regarding those quantities estimated by Ryder Scott of proved reserves of Laredo Petroleum, Inc. and its subsidiaries, the future net revenues from those reserves and their present value for the years ended December 31, 2021, 2020 and 2019, and to the inclusion of its summary report dated January 14, 2022 as an exhibit to the Annual Report. We further consent to the incorporation by reference thereof into Laredo Petroleum, Inc.'s Registration Statements on Form S-8 (File No. 333-178828, effective December 30, 2011 File No. 333-211610, effective May 25, 2016, and File No. 333-231593, effective May 20, 2019) and the Registration Statement of Laredo Petroleum, Inc. on Form S-3 (File No. 333-230427, effective March 21, 2019).

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 24, 2022

CERTIFICATION

I, Jason Pigott, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;
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 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: February 24, 2022

/s/ Jason Pigott

Jason Pigott

President and Chief Executive Officer

CERTIFICATION

I, Bryan J. Lemmerman, certify that:

1. I have reviewed this Annual Report on Form 10-K of Laredo Petroleum, Inc.;
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 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: February 24, 2022

/s/ Bryan J. Lemmerman

Bryan J. Lemmerman

Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

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

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Jason Pigott, President and Chief Executive Officer of Laredo Petroleum, Inc. (the "Company"), and Bryan J. Lemmerman, Senior Vice President and Chief Financial Officer of the Company, certify that, to their knowledge:

(1) the Annual Report on Form 10-K of the Company for the period ending December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (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 result of operations of the Company.

February 24, 2022

/s/ Jason Pigott
Jason Pigott
President and Chief Executive Officer

February 24, 2022

/s/ Bryan J. Lemmerman
Bryan J. Lemmerman

Senior Vice President and Chief Financial Officer

Mine Safety Disclosures

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

Laredo Petroleum, Inc., (“Laredo”), on April 15, 2020, acquired surface and sand rights on approximately 628 acres in Howard County, Texas, and in October 2020 entered into an agreement with Hi-Crush, Inc. and its subsidiary OnCore Processing, LLC (“OnCore”) to construct and operate an in-field sand mine to support Laredo’s exploration and development operations. Operations began in November 2020 and are subject to regulation by the U.S. Federal Mine Safety and Health Administration ("MSHA").

MSHA inspects mining facilities on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. Citations and orders may be appealed with the potential of reduced or dismissed penalties. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K (17 CFR 229.104) are outlined below.

Mine Safety Data

The following provides additional information about references used in the table below to describe the categories of violations, orders or citations issued by MSHA under the Mine Act:

- *Section 104 Significant Substantial (“S&S”) Citations:* Citations for violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a mine safety or health hazard.
- *Section 104(b) Orders:* Orders which represents a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.
- *Section 104(d) Citations and Orders:* Citations and orders for an unwarrantable failure to comply with mandatory health or safety standards.
- *Section 110(b)(2) Violations:* Flagrant violations.
- *Section 107(a) Orders:* Orders for situations in which MSHA determined an "imminent danger" (as defined by MSHA) existed.
- *Notice of Pattern of Violations*: Notice of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of mine health or safety hazards under section 104(e) of the Mine Act.
- *Notice of Potential Pattern of Violations*: Notice of the potential to have a pattern of violations under section 104(e).
- *Pending Legal Actions*: Legal actions before the Federal Mine Safety and Health Review Commission ("FMSHRC") initiated.

<u>For the year ended December 31, 2021</u>

Citation, Order, Violation or Action	OnCore[(a)]
Section 104 S&S citations (#)	None
Section 104(b) orders (#)	None
Section 104(d) citations and orders (#)	None
Section 110(b)(2) violations (#)	None
Section 107(a) orders (#)	None
Proposed assessments under MSHA ($)[(b)]	None
Mining-related fatalities (#)	None
Notice of pattern of violations (yes/no)	None
Notice of potential pattern of violations (yes/no)	None
Pending legal actions (#)	None

(a) The definition of mine under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting minerals, such as land, structures, facilities, equipment, machines, tools and minerals preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. MSHA assigns an identification number to each mine and may or may not assign separate identification numbers to related facilities such as preparation facilities. We are providing the information in the table by mine rather than MSHA identification number because that is how we manage and operate our mining business and we believe this presentation will be more useful to investors than providing information based on MSHA identification numbers.

(b) Represents the total dollar value of the proposed assessment from MSHA under the Mine Act pursuant to the citations and/ or orders preceding such dollar value in the corresponding row.

EXHIBIT 99.1

LAREDO PETROLEUM, INC.

SUMMARY REPORT

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2021

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.
TBPELS License No. 116149
Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580   FAX (713) 651-0849
1100 LOUISIANA SUITE 4600   HOUSTON, TEXAS 77002-5294   TELEPHONE (713) 651 -9191

January 14, 2022

Laredo Petroleum, Inc.
15 West 6th Street, Suite 900
Tulsa, Oklahoma 74119

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Laredo Petroleum, Inc. (Laredo) as of December 31, 2021. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 11, 2022 and presented herein, was prepared for public disclosure by Laredo in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Laredo as of December 31, 2021.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data Certain Leasehold
and Royalty Interests of
Laredo Petroleum, Inc.
As of December 31, 2021

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate – Mbbl	70,727	50,175	120,902
Plant Products – Mbbl	78,908	21,139	100,047
Gas – MMcf	494,476	91,669	586,145
MBOE	232,048	86,592	318,640
Income Data ($M)			
Future Gross Revenue	$7,353,660	$3,848,186	$11,201,846
Deductions	2,227,219	1,788,530	4,015,749
Future Net Income (FNI)	$5,126,441	$2,059,656	$7,186,097
Discounted FNI @ 10%	$2,797,988	$918,262	$3,716,250

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Laredo. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. Other costs include variable costs associated with transportation and processing fees. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 87 percent and gas reserves account for the remaining 13 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2021
Discount Rate Percent	Total Proved
5	$4,877,919
8	$4,102,665
12	$3,400,849
15	$3,023,142

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Laredo's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Laredo's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing**,** the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Laredo owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. Approximately 99 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through December 2021 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Laredo or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 1 percent of the proved producing reserves were estimated by analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

All of the proved undeveloped reserves included herein were estimated by analogy, or a combination of methods. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Laredo has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Laredo with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, workover and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Laredo. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange

Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Laredo. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Laredo furnished us with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Laredo.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Plains Pipeline	$63.04/bbl	$66.37/bbl
	NGLs	OPIS Composite(1)	$34.514/bbl	$22.90/bbl
	Gas	El Paso Permian	$3.35/MMBTU	$2.61/Mcf

(1) Price reflects composition of ethane, propane, butane, and pentane

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Laredo and are based on the operating expense reports of Laredo and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Laredo. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Laredo and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Laredo were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Laredo’s plans to develop these reserves as of December 31, 2021. The implementation of Laredo’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Laredo’s management. As the result of our inquiries during the course of preparing this report, Laredo has informed us that the development activities included herein have been subjected to and received the internal approvals required by Laredo’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Laredo. Laredo has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Laredo has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Laredo were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Laredo. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Laredo.

Laredo makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Laredo has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Laredo, of the references to our name, as well as to the references to our third party report for Laredo, which appears in the December 31, 2021 annual report on Form 10-K of Laredo. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Laredo.

We have provided Laredo with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Laredo and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.
TBPELS License No. 116149
Vice President **[SEAL]**

MEW (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Ms. Marsha E. Wellmann was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Ms. Wellmann, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2012, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America and the Gulf of Mexico. Before joining Ryder Scott, Ms. Wellmann served in a number of engineering positions. For more information regarding Ms. Wellmann's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Ms. Wellmann earned a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002 and is a registered Professional Engineer in the State of Texas. She is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Ms. Wellmann fulfills. As part of her 2021 continuing education hours, Ms. Wellmann attended 41 hours of formalized training including various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on her educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Ms. Wellmann has attained the professional qualifications as a Reserves Estimator set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

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

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

<u>DEVELOPED RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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.*

<u>Developed Producing (SPE-PRMS Definitions)</u>

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

<u>Developed Producing Reserves</u>
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.