UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2022

or

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

Commission file number: 001-35380

Vital Energy, 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.)

521 E. Second Street	**Suite 1000**	
Tulsa	**Oklahoma**	**74120**
(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	VTLE	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, 2022, based on $68.94 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 17, 2023: 17,149,215

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2023 Annual Meeting of Stockholders are incorporated by reference into Part III of this report for the year ended December 31, 2022.

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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"):

"*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.

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

"*MMBOE*"—One million BOE.

"*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.

"*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:

- continuing and worsening inflationary pressures and associated changes in monetary policy that may cause costs to rise;
- 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 our area of operation in the Permian Basin;
- reduced demand due to shifting market perception towards the oil and gas industry;
- our ability to optimize spacing, drilling and completions techniques in order to maximize our rate of return, cash flows from operations and shareholder value;
- 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;
- competition in the oil and gas industry;
- 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 acquisitions, including effectively managing our expanded acreage;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves and inventory;
- insufficient transportation capacity in the Permian Basin and challenges associated with such constraint, and the availability and costs of sufficient gathering, processing, storage and export capacity;
- a decrease in production levels which may impair our ability to meet our contractual obligations and ability to retain our leases;
- risks associated with the uncertainty of potential drilling locations and plans to drill in the future;
- the inability of significant customers to meet their obligations;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the effects, duration and other implications of, including government response to, the coronavirus ("COVID-19"), or the threat and occurrence of other epidemic or pandemic diseases;

- ongoing war and political instability in Ukraine and Russian efforts to destabilize the government of Ukraine and the global hydrocarbon market;
- loss of senior management or other key personnel;
- risks related to the geographic concentration of our assets;
- capital requirements for our operations and projects;
- our ability to hedge commercial risk, including commodity price volatility, and regulations that affect our ability to hedge such risks;
- our ability to continue to maintain the borrowing capacity under our Senior Secured Credit Facility (as defined herein) 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;
- 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 impact of legislation or regulatory initiatives intended to address induced seismicity on our ability to conduct our operations;
- 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;
- our ability to comply with federal, state and local regulatory requirements;
- the impact of repurchases, if any, of securities from time to time;
- 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;
- our ability to secure or generate sufficient electricity to produce our wells without limitations; and
- our belief that the outcome of any legal proceedings will not materially affect our financial results and operations.

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 "Vital," the "Company," "we," "our," "us," or similar terms refer to Vital Energy, 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

Vital Energy, Inc., together with its wholly-owned subsidiaries, is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties 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, 2022, we had assembled 163,286 net acres in the Permian Basin, all of which were held in 371 sections. Our acreage is largely contiguous in the neighboring Texas counties of Borden, Howard, Glasscock, Reagan, and Sterling. We have identified one operating segment: exploration and production.

Business Strategy and 2022 Operational Highlights

Our strategy is to create long-term value through the efficient development and acquisition of high-margin properties, combined with prudent balance sheet management and sustainable environmental practices. We have operated in the Permian Basin since 2008, drilling almost 650 operated horizontal wells. Our extensive operating experience in the basin underpins our ability to successfully develop our properties, assess acquisition opportunities and operate safely and efficiently, ultimately maximizing our rates of return on our development program.

Beginning in late 2019, we acquired oil-weighted properties to the north and west of our existing Permian Basin acreage and quickly transitioned our development activities to these capital-efficient areas. We have significantly increased our oil production as a percentage of total production, improved our operating margin and, as a result, generated Free Cash Flow and significantly reduced debt in 2022.

Our results in 2022 were driven by our development program in Howard County. We focused on developing large packages of wells at conservative spacing to maximize both current and future productivity. Combined with continued efficiency gains in our drilling and completions operations and sustained strength in oil prices, our development program generated high returns and Free Cash Flow. Additionally, we divested non-operated properties in Howard County for $110.0 million, generating additional cash flow and enhancing control of our capital investments.

We seek to proactively manage our financial risks and maintain a strong balance sheet. During 2022, we utilized Free Cash Flow and divestiture proceeds to repurchase, and retire, a total of $284.8 million in aggregate principal amount of our senior unsecured notes, thereby reducing our consolidated total leverage ratio to 1.2 times. We increased our borrowing base to $1.3 billion and our elected commitment to $1.0 billion, increasing our liquidity and financial flexibility. Additionally, in May 2022 we instituted an equity repurchase program as a method to return cash to shareholders. During 2022 we repurchased $37.3 million of equity, reducing shares outstanding by 490,536 shares. 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 2022 with approximately 73% of our expected oil production hedged to protect cash flow and we will continue to seek hedging opportunities on a multi-year basis, subject to the terms of our Senior Secured Credit Facility, to further protect our capital plan, interest payments, and Free Cash Flow generation.

We integrate robust environmental, social and governance ("ESG") practices into our operations and describe these practices in the three ESG and Climate Risk Reports we have published to date, covering operations which occurred in 2019, 2020 and 2021, respectively. The disclosures in these three reports are aligned to the Sustainability Accounting Standards Board, the Task Force on Climate Related Financial Disclosures, the International Petroleum Industry Environmental Conservation Association, the American Petroleum Institute, and the American Exploration and Production Council frameworks. Our 2020

report, related to our 2019 operations, 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, our 2022 report expanded our emissions reduction targets to include a 2025 target for the percentage of recycled water to be used in our completions operations as well as a 2030 combined Scope 1 and Scope 2 greenhouse gas intensity target. Beyond our emissions reduction targets, we also disclosed 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 the certification of portions of our oil and natural gas production as responsibly sourced through the Project Canary TrustWell™ Certification pilot project, the first operator in the Permian Basin to achieve this certification. Relatedly, we continue to incorporate 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 improve our margins and profitability. 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 currently 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 and Spraberry formations. As of December 31, 2022, we had an average working interest of 73% in Vital-operated active productive wells and 67% in all wells in which Vital has an interest, and our leases are 98% held by production.

The following table sets forth certain information regarding productive wells as of December 31, 2022. Wells are classified as oil or natural gas wells according to the predominant production stream. All but sixteen 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	947	742	1,689	1,235	73 %
Non-operated	163	64	227	57	25 %
Total	1,110	806	1,916	1,292	67 %

Drilling Activity

On December 31, 2022, we had two drilling rigs drilling horizontal wells and one completions crew. We anticipate running two drilling rigs and two completions crews in the first quarter of 2023. For the remainder of 2023, we anticipate running two drilling rigs and one completions crew. We will adjust our drilling rig count and/or completions crews to maximize efficiencies and cash flow. If we decrease our drilling rig count and/or completions 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 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,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Productive development wells	49	47.1	71	70.1	48	47.3

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."

	Years ended December 31,			2022 compared to 2021	
	2022	2021	2020	Change (#)	Change (%)
Sales volumes:					
Oil (MBbl)	13,838	11,619	9,827	2,219	19 %
NGL (MBbl)	8,028	8,678	10,615	(650)	(7)%
Natural gas (MMcf)	49,259	57,175	70,049	(7,916)	(14)%
Oil equivalents (MBOE)(1)(2)	30,076	29,827	32,117	249	1 %
Average daily oil equivalent sales volumes (BOE/D)(2)	82,400	81,717	87,750	683	1 %
Average daily oil sales volumes (Bbl/D)(2)	37,912	31,833	26,849	6,079	19 %
Sales revenues (in thousands):					
Oil	$1,351,207	$ 805,448	$ 367,792	$ 545,759	68 %
NGL	$ 234,613	$ 191,591	$ 78,246	$ 43,022	22 %
Natural gas	$ 208,554	$ 150,104	$ 50,317	$ 58,450	39 %
Average sales prices(2):					
Oil ($/Bbl)(3)	$ 97.65	$ 69.32	$ 37.43	$ 28.33	41 %
NGL ($/Bbl)(3)	$ 29.22	$ 22.08	$ 7.37	$ 7.14	32 %
Natural gas ($/Mcf)(3)	$ 4.23	$ 2.63	$ 0.72	$ 1.60	61 %
Average sales price ($/BOE)(3)	$ 59.66	$ 38.46	$ 15.45	$ 21.20	55 %
Oil, with commodity derivatives ($/Bbl)(4)	$ 70.32	$ 52.09	$ 56.41	$ 18.23	35 %
NGL, with commodity derivatives ($/Bbl)(4)	$ 24.29	$ 10.55	$ 9.12	$ 13.74	130 %
Natural gas, with commodity derivatives ($/Mcf)(4)	$ 2.83	$ 1.56	$ 1.02	$ 1.27	81 %
Average sales price, with commodity derivatives ($/BOE)(4)	$ 43.48	$ 26.36	$ 22.50	$ 17.12	65 %
Selected average costs and expenses per BOE sold(1)(2):					
Lease operating expenses	$ 5.78	$ 3.42	$ 2.55	$ 2.36	69 %
Production and ad valorem taxes	3.69	2.30	1.03	1.39	60 %
Transportation and marketing expenses	1.79	1.61	1.55	0.18	11 %
General and administrative (excluding LTIP)	1.91	1.54	1.29	0.37	24 %
Total selected operating expenses	$ 13.17	$ 8.87	$ 6.42	$ 4.30	48 %
General and administrative (LTIP):					
LTIP cash	$ 0.11	$ 0.35	$ 0.06	$ (0.24)	(69)%
LTIP non-cash	$ 0.24	$ 0.22	$ 0.22	$ 0.02	9 %
Depletion, depreciation and amortization	$ 10.36	$ 7.22	$ 6.76	$ 3.14	43 %

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

(2) The numbers presented in the years ended December 31, 2022, 2021 and 2020 columns are based on actual amounts and may not recalculate 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 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, 2022					Year ended December 31, 2022			
	Estimated proved reserves[(1)]			Producing wells		Average daily production			
	MBOE	% Oil	Net acreage	Gross	Net	(BOE/D)	% Oil	% NGL	% Natural gas
Permian-Midland Basin	302,318	39 %	163,286	1,916	1,292	82,400	46 %	27 %	27 %

(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, 2022 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, 2022	December 31, 2021
Proved developed:		
Oil (MBbl)	70,333	70,727
NGL (MBbl)	75,156	78,908
Natural gas (MMcf)	464,567	494,476
Total proved developed (MBOE)	222,917	232,048
Proved undeveloped:		
Oil (MBbl)	46,125	50,175
NGL (MBbl)	18,656	21,139
Natural gas (MMcf)	87,721	91,669
Total proved undeveloped (MBOE)	79,401	86,592
Estimated proved reserves:		
Oil (MBbl)	116,458	120,902
NGL (MBbl)	93,812	100,047
Natural gas (MMcf)	552,288	586,145
Total estimated proved reserves (MBOE)	302,318	318,640
Percent developed	74 %	73 %

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, 2022, 2021 and 2020 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.

Our Director of Reserves serves as the technical person primarily responsible for overseeing the preparation of our reserves estimates. She has more than 20 years of practical experience, with 8 years of this experience being in the estimation and evaluation of reserves. She has a Bachelor of Science in Petroleum Engineering from the Missouri University of Science and Technology. Our Director of Reserves reports 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 decreased from 86,592 MBOE as of December 31, 2021 to 79,401 MBOE as of December 31, 2022. We estimate that we incurred $337.9 million of costs to convert 23,722 MBOE of proved undeveloped reserves from 44 locations into proved developed reserves in 2022. New proved undeveloped reserves of 30,291 MBOE were added during the year from 34 Spraberry and 32 Wolfcamp locations. 13,155 MBOE of negative revisions consisted of 9,785 MBOE of negative revisions due to 16 proved undeveloped locations that were removed due to change in the development plan and 3,370 MBOE of negative revisions from a decrease in previously estimated quantities due to performance, price and other changes. A final investment decision has been made on all 153 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, 2022 reserve report are $1.3 billion. 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 $529.0 million in 2023, $321.0 million in 2024, $222.7 million in 2025, $128.6 million in 2026 and $14.6 million in 2027. 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 2023 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, 2022, 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		%
	Gross	Net	Gross	Net	Gross	Net	HBP
Permian-Midland Basin	183,914	160,496	3,344	2,790	187,258	163,286	98 %

The following table sets forth our gross and net undeveloped acreage as of December 31, 2022 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,							
	2023		2024		2025		2026	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian-Midland Basin	474	543	1,390	1,138	600	307	—	—

Of the total undeveloped acreage identified as potentially expiring over the next five years as of December 31, 2022, 1,881 net acres have associated PUD reserves included in our reserve report as of December 31, 2022, which we anticipate drilling to hold or renewing the associated leases. These PUD reserves represent 35% of our total PUD reserves as of December 31, 2022.

Of the total undeveloped acreage identified as potentially expiring over the next five years as of December 31, 2021, 2,355 net acres had associated PUD reserves on our reserve report as of December 31, 2021. Of the total undeveloped acreage identified as potentially expiring in 2022, zero net acres were not retained through either 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, 2022:

	Total	2023	2024	2025	2026 and after
Crude oil (MBbl):					
Sales commitments	7,875	7,875	—	—	—
Transportation commitments:					
Field	21,930	10,950	10,980	—	—
To U.S. Gulf Coast	54,285	12,775	12,810	12,775	15,925
Natural gas (MMcf):					
Sales commitments	54,378	11,402	8,435	7,378	27,163
Total commitments (MBOE)[(1)]	93,153	33,500	25,196	14,005	20,452

(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 transport oil from our production area to major market hubs, including Midland, Texas and Crane, Texas. If not fulfilled, we are subject to transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for our business. Our firm field transportation agreements 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. In addition, we have a transportation commitment with Gray Oak Pipeline, LLC extending into 2027 to transport 35,000 barrels of oil per day of our production, or the oil purchased from third parties, from Crane, Texas to the U.S. Gulf Coast. We believe these commitments enhance our ability to efficiently market our crude oil at various locations both in and 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 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, 2022, 2021 and 2020, 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 pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the “2016 PIPES Act”), 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. In December 2020, the “Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020” (the “2020 PIPES Act”), was signed into law. The 2020 PIPES Act extends the PHMSA’s statutory mandate through 2023. It continues the legislative and regulatory mandates that were established in the 2016 PIPES Act and creates new mandates for PHMSA to abide by. Some of the key PHMSA regulations enacted in response to these pieces of legislation include final rules published on October 1, 2019, which took effect on July 1, 2020 to expand PHMSA’s integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside high consequence areas. The rules also extend reporting requirements to certain previously unregulated hazardous liquid gravity and rural gathering lines. Also, on June 7, 2021, the PHMSA issued an advisory bulletin reminding pipeline owners and operators that they must take several steps to eliminate hazardous leaks and minimize releases of natural gas by December 27, 2021 pursuant to directives set forth in the 2020 PIPES Act. In addition, 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 final rules were announced in 2022, including a final rule regarding the installation of rupture-mitigation valves, published on April 8, 2022. Further, on August 24, 2022, the PHMSA published a final rule strengthening integrity management requirements for onshore gas transmission lines, bolstering corrosion control standards and repair criteria, and imposing new requirements for inspections after extreme weather events. Compliance with these regulations 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, 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 Clean Water Act has fluctuated in recent years. On June 29, 2015, the EPA and the Corps jointly promulgated final rules expanding 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 January 18, 2023, the EPA and the Corps published a final rule that would restore water protections that were in place prior to 2015. Meanwhile, in October 2022, the Supreme Court heard oral argument in a case addressing the scope of federal jurisdiction under the Clean Water Act. 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 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. Also, 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. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, 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.

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, strict and stringent regulations governing emissions of toxic air pollutants at specified sources; emissions from specific sources such as tanks,

engines, dehydration units, and heaters; and maintenance requirements for such equipment. 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 and monitor 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. On November 15, 2021, the EPA published a proposed rule for oil and natural gas facilities that would expand control requirements, increase LDAR inspection frequencies, prohibit venting of natural gas in certain situations, require equipment retrofits, and regulate older facilities. Also, on December 6, 2022, the EPA published a supplemental proposal to strengthen the emission reduction requirements, which would, among other things, expand LDAR requirements and tighten flaring restrictions.

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. On November 30, 2022, the BLM published a proposed replacement rule to reduce the waste of natural gas from venting, flaring and leaks during oil and gas production activities on federal and Indian lands, which would require the use of upgraded equipment in some cases and would place time and volume limits on royalty-free flaring. 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, which were not material, to comply 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 needed to comply 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"). In August 2022, President Biden signed the Inflation Reduction Act of 2022 (“IRA”) into law. The IRA contains billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration, amongst other provisions. These incentives could accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we produce and sell. In addition, the IRA imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The IRA amends the Clean Air Act to impose a fee on the emission of methane that exceeds an applicable waste emissions threshold from sources required to report their GHG emissions to the EPA, including those sources in the offshore and onshore petroleum and natural gas production and gathering and boosting source categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA.

The EPA has also finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry and almost one-half of the states have 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, several 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. In relation, 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 newly listed species, such as the lesser prairie chicken, are located in areas where we operate or 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, 2022, 2021 or 2020.

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 took 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. 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 *Vital Way* is a path designed for our employees to experience mutual respect, openness, honesty and a spirit of trust and collaboration while employed by Vital. Vital'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. The Vital Way separates itself by advancing a limitless mindset. Diverse and sound ideas, approaches and individual experiences are essential features of inclusion. By choosing to practice a mindset unencumbered by bias or fear, we believe there are no barriers to what we can become. Through the implementation of our Code of Conduct and Business Ethics, annual anti-harassment training and unconscious bias trainings, we uphold an environment of safety and inclusion. We firmly believe that everyone at Vital contributes to our success.

Workforce Composition

As of December 31, 2022, we employed 289 full-time employees, 141 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, Vital 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 2022, our workforce consisted of:

- 28% diverse based on ethnicity
- 28% diverse based on gender
- 3% US military veterans
- 37% women in professional roles or higher

Vital 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 *Vital Way*.

Health and Safety

Vital Energy exists to help people reach their fullest potential. We believe this starts with making sure people are healthy and safe. Most importantly, we know that an engaged, healthy, safe and well-trained workforce helps us accomplish our strategic goals. By taking action every day through all-hands safety meetings, hazard hunts, stop-work authority and root-cause analysis, we are building belief in this culture every day.

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. 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.

Learning and Development

Attracting, retaining and developing our workforce is crucial to all aspects of Vital's overall success and it is central to our long-term strategy. 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 leadership 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. Vital prides itself on the ability to promote our great employees.

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 "VTLE."

We also make available on our website (http://www.vitalenergy.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, corporate governance, environmental and social 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.

Risks related to our business

Continuing or worsening inflationary pressures and associated changes in monetary policy have resulted in and may result in additional increases to our drilling and completions costs and costs of oilfield services, equipment, and materials, which in turn have caused and may continue to cause our capital expenditures and operating costs to rise.

The U.S. inflation rate increased in 2021 and 2022 and may continue to increase in 2023. These inflationary pressures have resulted in and may result in additional increases to our drilling and completions costs and costs of oilfield services, equipment, and materials, which in turn have caused and may continue to cause our capital expenditures and operating costs to rise. Sustained levels of high inflation have likewise caused the Federal Reserve and other central banks to increase interest rates, which could have the effects of raising the cost of capital and depressing economic growth, either of which — or the combination thereof — could hurt the financial and operating results of our business.

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 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, lower oil, NGL and natural gas prices could lead to a reduced borrowing base under our Senior Secured Credit Facility, which could trigger repayments under such facility. Also, lower oil, NGL and natural gas prices would likely cause a decline in our stock price.

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 continue to 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.

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.

In addition, we use 3D seismic and other advanced technologies, which are relatively unproven and require 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.

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 (i) recoverable reserves; (ii) future oil, NGL and natural gas prices and their applicable differentials; (iii) timing of development; (iv) capital and operating costs; and (v) 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 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.

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 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 and operations may be further affected by the COVID-19 pandemic and responses.

Since 2020, 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 and severity of new and different strains of the virus; 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; a competitive labor market due to 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 practices 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.

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 with the intensification 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. Russia's activities in Ukraine have caused, and could intensify, 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.

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, 2022, 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, 2022, we had federal net operating loss ("NOL") carryforwards totaling $1.5 billion and state of Oklahoma NOL carryforwards totaling $34.4 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, periodically promulgated by the IRS. 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 This annual litigation however, may be significantly increased if there is "net unrealized built-in gain" in the assets of the corporation undergoing the ownership change.

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 20-year 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, 2022, 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, 2022, 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 (i) 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, (ii) abnormally pressured formations, (iii) mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse, (iv) fires, explosions and ruptures of pipelines, (v) disagreements regarding the royalty due to our royalty owners, (vi) personal injuries and death, (vii) electronic system disruption and cyber-security threats, (viii) natural disasters and (ix) 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.

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.

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 within the announced timelines, or at all or comply with ethical, environmental, or other standards, including reporting standards, may adversely impact 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 (i) production is less than the volume covered by the commodity derivative instruments; (ii) the counter-party to the commodity derivative instrument defaults on its contractual obligations; (iii) there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or (iv) 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 11 and 12 to our consolidated financial statements included elsewhere in this Annual Report.

We may incur significant additional amounts of debt.

As of December 31, 2022, we had total long-term indebtedness of $1.12 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.

We require continued access to capital. 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. Disruptions and volatility in the global financial markets and a downgrade in our credit ratings could negatively impact our costs of capital and 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 Term SOFR, a forward-looking term rate that is based on the secure overnight financing rate determined by the Federal Reserve bank of New York. SOFR is a volume weighted measure of the cost of overnight borrowings collateralized by treasury securities and can fluctuate based on multiple factors. In response to inflation, the U.S. Federal Reserve increased rates several times in 2022 and signaled that additional interest rate increases should be expected in 2023. On December 14, 2022, it raised interest rates by 0.50%, representing the seventh increase in interest rates during 2022 to date. Raising or lowering of interest rates by the U.S. Federal Reserve generally causes an increase or decrease, respectively, in SOFR and other floating interest rate benchmarks. As such, if interest rates increase, so will our interest costs. 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.

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 or debt 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, as well as our ability to repay borrowings under our Senior Secured Credit Facility or any other obligation if required.

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 (i) lower commodity prices or production, (ii) increased leverage ratios, (iii) inability to drill or unfavorable drilling results, (iv) changes in oil, NGL and natural gas reserves engineering, (v) increased operating and/or capital costs, (vi) the lenders' inability to agree to an adequate borrowing base or (vii) 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 debt agreements contain, and any future indebtedness we incur may contain, various covenants that limit the manner in which we operate our business and our ability to engage in specified types of transactions. These covenants limit our ability to, among other things (i) incur additional indebtedness; (ii) pay dividends on, repurchase or redeem stock; (iii) make certain investments; (iv) sell, transfer or dispose of assets; (v) hedge our production; (vi) consolidate or merge; and (vii) enter into certain transactions with our affiliates.

A breach of any of these covenants could result in a default under one or more of these agreements and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it on terms acceptable to us. Furthermore, we have pledged substantially all of our assets as collateral to secure the debt under our Senior Secured Credit Facility and if we were unable to repay such debt, the lenders could proceed against such collateral. The proceeds from the sale or foreclosure upon such collateral will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay such debt to our unsecured indebtedness thereafter.

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.

In August 2022, President Biden signed into law the Inflation Reduction Act of 2022 ("IRA"). The IRA contains billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA imposes the first ever federal fee on emission of GHGs through a methane emissions charge, which will be phased-in starting in 2024. The IRA could accelerate the transition of the economy away from the use of fossil fuels towards lower-or-zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we produce and sell, which could have an adverse effect on our business, financial condition and results of operations.

Additional 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.

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. 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, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, 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, results of operations, financial condition and cash flow.

In addition, the IRA imposes a 15% corporate alternative minimum tax ("CAMT") on the "adjusted financial statement income" of certain large corporations (generally, corporations reporting at least $1 billion average adjusted pre-tax net income in their consolidated financial statements) as well as an excise tax of 1% on the fair market value of certain public company stock repurchases for tax years beginning after December 31, 2022. The U.S. Treasury Department, the Internal Revenue Service and other standard-setting bodies are expected to issue guidance on how the CAMT, stock buyback excise tax, and other provisions of the IRA will be applied or otherwise administered. We continue to evaluate the IRA and its effect on our financial results and operating cash flow.

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 presence of newly listed species, such as the lesser prairie chicken, or 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.

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 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 "VTLE."

As of February 17, 2023, there were 113 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 Vital:

Period	Total number of shares purchased	Weighted-average price paid per share[(1)]	Total number of shares purchased as part of publicly announced program[(2)]	Maximum value that may yet be purchased under the program as of the respective period-end date[(2)]
October 1, 2022 - October 31, 2022	100,749	$ 66.87	100,749	$ 166,676,279
November 1, 2022 - November 30, 2022	59,939	$ 66.17	59,939	$ 162,710,185
December 1, 2022 - December 31, 2022	—	$ —	—	$ 162,710,185
Total	160,688		160,688	

(1) Average share price includes any commissions paid to repurchase stock.

(2) On May 31, 2022, our board of directors authorized a $200 million share repurchase program commencing on the date of such announcement and continuing through and including May 27, 2024. Share repurchases under the program may be made through a variety of methods, which may include open market purchases, including under plans complying with Rule 10b5-1 of the Exchange Act, and privately negotiated transactions. During the three months ended December 31, 2022, we repurchased 160,688 shares under this program at a cost of $10.7 million.

Unregistered Sales of Equity Securities and Use of Proceeds

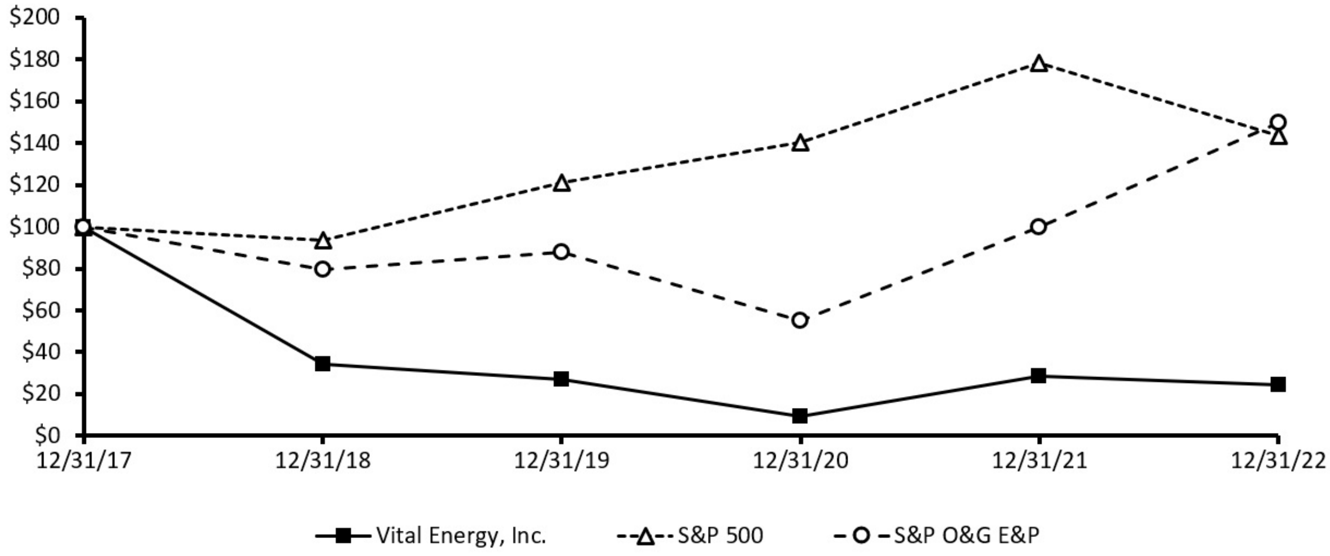
None.

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 assumption:

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 31, 2017 to December 31, 2022



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, 2022 compared to 2021, 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 2021 Annual Report on Form 10-K for discussion and analysis of our financial condition and results of operations for the year ended December 31, 2021 compared to 2020. 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 in the Permian Basin of West Texas. We have grown primarily through our drilling program, coupled with select strategic acquisitions and joint ventures.

As of December 31, 2022, we were operating two drilling rigs and one completions crew. We expect to operate two drilling rigs during 2023, with two completions crews during the first quarter of 2023 and returning to one completions crew for the remainder of 2023. Our expected capital expenditures for full-year 2023 are expected to be in the approximate range of $625.0 million to $675.0 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. Below is a summary of our financial and operating performance for the periods presented:

	Years ended December 31,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change (#)**	**Change (%)**
Oil sales volumes (MBbl)	13,838	11,619	2,219	19 %
Oil equivalents sales volumes (MBOE)	30,076	29,827	249	1 %
Oil, NGL and natural gas sales[1]	$ 1,794,374	$ 1,147,143	$ 647,231	56 %
Net income	$ 631,512	$ 145,008	$ 486,504	336 %
Net cash provided by operating activities	$ 829,620	$ 496,671	$ 332,949	67 %
Free Cash Flow (a non-GAAP financial measure)[2]	$ 219,941	$ (2,829)	$ 222,770	7,875 %
Adjusted EBITDA (a non-GAAP financial measure)[2]	$ 913,482	$ 505,917	$ 407,565	81 %
Proved developed and undeveloped reserves (MBOE)[3]	302,318	318,640	(16,322)	(5)%

(1) Our oil, NGL and natural gas sales increased as a result of a 55% increase in average sales price per BOE and a 19% increase in oil sales volumes.

(2) See pages 57-58 for discussion and calculations of these non-GAAP financial measures.

(3) See Note 19 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

Vital Energy rebranding

Effective January 9, 2023, the Company changed its corporate name from Laredo Petroleum, Inc. to Vital Energy, Inc., pursuant to a certificate of amendment to its certificate of incorporation filed with the Delaware Secretary of State on January 6, 2023. The Company also amended and restated its bylaws to reflect the name change, effective as of January 9, 2023.

Volatility in commodity prices

Commodity prices remained steady during the fourth quarter of 2022, sustaining levels reached at the end of the first quarter as increased commodity demand has continued to outpace relative supply. While recessionary concerns have placed some downward pressure on commodity prices, causing oil and gas prices to retreat from their earlier highs in 2022, worldwide commodity demand continues to exceed pre-COVID-19 pandemic levels. Although supply has increased, it has been constrained and pricing has been affected, in part, by the impact of the Russian-Ukrainian military conflict on global commodity and financial markets, and the resulting effect of sanctions by the European Union, United Kingdom and U.S. on imports of oil and natural gas from Russia, as well as a recent announcement by OPEC+ of oil production cuts of two million barrels per day beginning in November of 2022. However, because any of the above factors could suddenly change or reverse, global commodity and financial markets remain subject to heightened levels of uncertainty and volatility, and future disruptions and industry-specific impacts could result.

Rising inflation and interest rates

Reversing a trend experienced in 2020 in connection with the impact of COVID-19 and historically low crude oil prices, drilling and completions costs and costs of oilfield services, equipment and materials began to rise in 2021 and continued to persist at elevated levels in 2022 in conjunction with the significant increase in commodity prices, labor tightening, supply chain disruptions caused by the COVID-19 pandemic and the resulting limited availability of certain materials and products manufactured using such materials and heightened levels of inflation. In addition to the effect of such inflationary pressures on our operating and capital costs, rising interest rates as a result of the Federal Reserve’s tightening monetary policy have increased our borrowing costs on debt under our Senior Secured Credit Facility and may limit our ability to access debt capital markets. Additional increases in interest rates have the potential to increase our costs of borrowing even more. We remain committed to our ongoing efforts to increase the efficiency of our operations and improve costs, which may, in part, offset cost increases from inflation and reduce our borrowing needs.

See Note 18 to our consolidated financial statements included elsewhere in this Annual Report for discussion of recent developments that have occurred subsequent to December 31, 2022.

Pricing and reserves

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. We maintain an active commodity derivatives strategy to minimize commodity price volatility and support cash flows for operations. 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 11, 12 and 18 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our commodity derivatives. Not withstanding our derivatives strategy, 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.

Our reserves are reported in three streams: oil, NGL and natural gas. The Realized Prices, which are utilized to value our proved reserves and calculated using the average first-day-of-the-month prices for each month within the 12-month period prior to the end of the reporting period, adjusted for factors affecting price received at the delivery point, as of December 31, 2022 were $96.21 for oil, $29.84 for NGL and $4.24 for natural gas. The unamortized cost of evaluated oil and natural gas properties being depleted did not exceed the full cost ceiling for any of the quarterly periods in 2022 and 2021. As such, no full cost ceiling impairments were recorded during the years ended December 31, 2022 and 2021. Oil prices have declined from mid-2022 levels, however, even with this decline if oil prices remain at current levels, we do not anticipate recording full cost ceiling impairments for the foreseeable future. See Notes 2 and 6 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 primarily derived from the sale of produced oil, NGL and natural gas and the sale of purchased oil, all within the continental U.S. and do not include the effects of derivatives.

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,		2022 compared to 2021	
	2022	2021	Change (#)	Change (%)
Oil sales	70 %	58 %	12 %	21 %
NGL sales	12 %	14 %	(2)%	(14)%
Natural gas sales	11 %	11 %	— %	— %
Sales of purchased oil	7 %	17 %	(10)%	(59)%
Other operating revenues	— %	— %	— %	— %
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,		2022 compared to 2021	
	2022	2021	Change (#)	Change (%)
Sales volumes:				
Oil (MBbl)	13,838	11,619	2,219	19 %
NGL (MBbl)	8,028	8,678	(650)	(7)%
Natural gas (MMcf)	49,259	57,175	(7,916)	(14)%
Oil equivalents (MBOE)[(1)(2)]	30,076	29,827	249	1 %
Average daily oil equivalent sales volumes (BOE/D)[(2)]	82,400	81,717	683	1 %
Average daily oil sales volumes (Bbl/D)[(2)]	37,912	31,833	6,079	19 %
Sales revenues (in thousands):				
Oil	$ 1,351,207	$ 805,448	$ 545,759	68 %
NGL	234,613	191,591	43,022	22 %
Natural gas	208,554	150,104	58,450	39 %
Total oil, NGL and natural gas sales revenues	$ 1,794,374	$ 1,147,143	$ 647,231	56 %
Average sales prices[(2)]:				
Oil ($/Bbl)[(3)]	$ 97.65	$ 69.32	$ 28.33	41 %
NGL ($/Bbl)[(3)]	$ 29.22	$ 22.08	$ 7.14	32 %
Natural gas ($/Mcf)[(3)]	$ 4.23	$ 2.63	$ 1.60	61 %
Average sales price ($/BOE)[(3)]	$ 59.66	$ 38.46	$ 21.20	55 %
Oil, with commodity derivatives ($/Bbl)[(4)]	$ 70.32	$ 52.09	$ 18.23	35 %
NGL, with commodity derivatives ($/Bbl)[(4)]	$ 24.29	$ 10.55	$ 13.74	130 %
Natural gas, with commodity derivatives ($/Mcf)[(4)]	$ 2.83	$ 1.56	$ 1.27	81 %
Average sales price, with commodity derivatives ($/BOE)[(4)]	$ 43.48	$ 26.36	$ 17.12	65 %

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

(2) The numbers presented in the years ended December 31, 2022 and 2021 columns are based on actual amounts and may not recalculate 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 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 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:

	Years ended December 31,		2022 compared to 2021	
(in thousands)	2022	2021	Change ($)	Change (%)
Net settlements paid for matured commodity derivatives:				
Oil	$ (378,163)	$ (158,612)	$ (219,551)	(138)%
NGL	(39,587)	(100,029)	60,442	60 %
Natural gas	(68,965)	(60,810)	(8,155)	(13)%
Total	$ (486,715)	$ (319,451)	$ (167,264)	(52)%
Net premiums paid previously or upon settlement attributable to commodity derivatives that matured during the respective period:				
Oil	$ —	$ (41,553)	$ 41,553	100 %

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, 2022 and 2021:

(in thousands)	Oil	NGL	Natural gas	Total
2021 Revenues	$ 805,448	$ 191,591	$ 150,104	$ 1,147,143
Effect of changes in average sales prices	391,955	57,373	79,233	528,561
Effect of changes in sales volumes	153,804	(14,351)	(20,783)	118,670
2022 Revenues	$ 1,351,207	$ 234,613	$ 208,554	$ 1,794,374
Change ($)	$ 545,759	$ 43,022	$ 58,450	$ 647,231
Change (%)	68 %	22 %	39 %	56 %

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

	Years ended December 31,		2022 compared to 2021	
(in thousands)	2022	2021	Change ($)	Change (%)
Sales of purchased oil	$ 119,408	$ 240,303	$ (120,895)	(50)%

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 the Gray Oak pipeline and we utilize purchased oil to fulfill portions of our commitments. In previous periods, we also utilized purchased oil to fulfill portions of our Bridgetex pipeline commitment, which ended during the first quarter of 2022. 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 decreased during the year ended December 31, 2022 compared to 2021 primarily due to a decrease in the volumes of purchased oil as our Bridgetex pipeline commitment ended during the first quarter of 2022, partially offset by an increase in sales prices.

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. 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 select information regarding costs and expenses and selected average costs and expenses per BOE sold for the periods presented and corresponding changes for such periods:

(in thousands except for per BOE sold data)	Years ended December 31, 2022	Years ended December 31, 2021	2022 compared to 2021 Change ($)	2022 compared to 2021 Change (%)
Costs and expenses:				
Lease operating expenses	$ 173,983	$ 101,994	$ 71,989	71 %
Production and ad valorem taxes	110,997	68,742	42,255	61 %
Transportation and marketing expenses	53,692	47,916	5,776	12 %
Costs of purchased oil	122,118	251,061	(128,943)	(51)%
General and administrative (excluding LTIP)	57,501	45,906	11,595	25 %
General and administrative (LTIP):				
LTIP cash	3,307	10,299	(6,992)	(68)%
LTIP non-cash	7,274	6,596	678	10 %
Organizational restructuring expenses	10,420	9,800	620	6 %
Depletion, depreciation and amortization	311,640	215,355	96,285	45 %
Impairment expense	40	1,613	(1,573)	(98)%
Other operating expenses, net	8,583	6,381	2,202	35 %
Total costs and expenses	$ 859,555	$ 765,663	$ 93,892	12 %
Gain (loss) on disposal of assets, net	(1,079)	84,551	(85,630)	(101)%
Selected average costs and expenses per BOE sold[(1)]:				
Lease operating expenses	$ 5.78	$ 3.42	$ 2.36	69 %
Production and ad valorem taxes	3.69	2.30	1.39	60 %
Transportation and marketing expenses	1.79	1.61	0.18	11 %
General and administrative (excluding LTIP)	1.91	1.54	0.37	24 %
Total selected operating expenses	$ 13.17	$ 8.87	$ 4.30	48 %
General and administrative (LTIP):				
LTIP cash	$ 0.11	$ 0.35	$ (0.24)	(69)%
LTIP non-cash	$ 0.24	$ 0.22	$ 0.02	9 %
Depletion, depreciation and amortization	$ 10.36	$ 7.22	$ 3.14	43 %

(1) Selected average costs and expenses per BOE sold are based on actual amounts and may not recalculate 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, 2022 compared to 2021. 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. LOE increased during 2022 due to inflationary pressures and costs associated with integrating our assets from the Sabalo/Shad Acquisition and Pioneer Acquisition, primarily driven by costs related to artificial lift and flowback management. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to LOE. Total LOE is expected to increase for 2023 as more of our production shifts to high-value Howard County wells, where, among other things, we have higher water production, resulting in increased water handling and lifting costs.

Production and ad valorem taxes

Production and ad valorem taxes increased for the year ended December 31, 2022 compared to 2021 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 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 increased for the year ended December 31, 2022 compared to 2021. These are expenses incurred for the delivery of produced oil to customers in the U.S. Gulf Coast market via the Gray Oak pipeline and, in previous years and the first quarter of 2022, the Bridgetex 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 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our transportation commitments.

Costs of purchased oil

During the year ended December 31, 2022, we were a firm shipper on the Gray Oak pipeline and we utilized purchased oil to fulfill portions of our commitments. In previous years and the first quarter of 2022, we also utilized purchased oil to fulfill portions of our Bridgetex pipeline commitment, which ended during the first quarter of 2022. In the event our long-haul transportation capacity on the 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. Costs of purchased oil decreased for the year ended December 31, 2022, compared to the same period in 2021 primarily due to a decrease in the volumes of purchased oil on pipelines as our Bridgetex pipeline commitment ended during the first quarter of 2022 and an increase in produced oil volumes, partially offset by an increase in sales prices.

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, 2022 compared to 2021 mainly due to (i) increases in workforce and professional expenses and (ii) inflationary pressures.

LTIP cash expense decreased for the year ended December 31, 2022 compared to 2021. These decreases are primarily due to (i) forfeitures of cash-settled performance unit awards in connection with the departure of our former Senior Vice President and Chief Operating Officer during the third quarter of 2022 and (ii) a decrease in the fair values of our cash-settled LTIP awards during the year ended December 31, 2022, mainly due to the performance of our stock during the period.

LTIP non-cash expense increased for the year ended December 31, 2022 compared to 2021, mainly due to new share-settled LTIP awards granted to our employees during the second half of 2021 and the first half of 2022, and partially offset by forfeitures of share-settled LTIP awards in connection with the departure of our former Senior Vice President and Chief Operating Officer during the third quarter of 2022. See Notes 2, 9 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 increased for the year ended December 31, 2022 compared to 2021. Such expenses were incurred for (i) the departure our former Senior Vice President and Chief Operating Officer during the third quarter of 2022 and (ii) a workforce reduction during the second quarter of 2021. 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 depletion expense per BOE sold for the periods presented and the corresponding changes for such periods:

	Years ended December 31,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change ($)**	**Change (%)**
Depletion expense per BOE sold	$ 9.92	$ 6.76	$ 3.16	47 %

Depletion expense per BOE increased for the year ended December 31, 2022 compared to 2021 primarily due to an increase in the book value of our oil and natural gas properties as a result of the Sabalo/Shad Acquisition and Pioneer Acquisition and the associated development costs, which includes the effects of inflationary pressures.

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

Gain (loss) on disposal of assets, net

Gain (loss) on disposal of assets, net, decreased for the year ended December 31, 2022 compared to 2021, primarily due to the gain recorded in third-quarter 2021 in connection with the Working Interest Sale. See Note 4 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion regarding the gain on the Working Interest Sale. 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 on the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price.

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,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change ($)**	**Change (%)**
Loss on derivatives, net	$ (298,723)	$ (452,175)	$ 153,452	34 %
Interest expense	(125,121)	(113,385)	(11,736)	(10)%
Loss on extinguishment of debt, net	(1,459)	—	(1,459)	(100)%
Other income, net	2,155	1,250	905	72 %
Total non-operating expense, net	$ (423,148)	$ (564,310)	$ 141,162	25 %

Loss on derivatives, net

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

	Years ended December 31,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change ($)**	**Change (%)**
Non-cash gain (loss) on derivatives, net	$ 185,573	$ (140,348)	$ 325,921	232 %
Settlements paid for matured derivatives, net	(486,753)	(320,868)	(165,885)	(52)%
Settlements received for contingent consideration	2,457	—	2,457	100 %
Premiums received for commodity derivatives	—	9,041	(9,041)	(100)%
Loss on derivatives, net	$ (298,723)	$ (452,175)	$ 153,452	34 %

Non-cash gain (loss) on derivatives, net is the result of (i) new and matured 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) 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 for matured derivatives, net 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.

We classify the derivatives gains and losses as operating activities and cash received for contingent consideration derivatives as investing activities in our consolidated statements of cash flows. See Notes 2, 4, 11, 12 and 18 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, 2022 compared to 2021. 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) commitment fees and (iii) annual agency fees in interest expense. During the third quarter of 2021, we completed the offering of the July 2029 Notes, with interest payable semi-annually commencing January 31, 2022 with interest from closing to that date. The increase during the year ended December 31, 2022 reflects a full year-to-date of interest expense incurred for the July 2029 Notes and higher interest expense on outstanding balances under our Senior Secured Credit Facility resulting from increases in interest rates by the U.S. Federal Reserve. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and interest expense.

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,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change ($)**	**Change (%)**
Current	$ (6,121)	$ (1,324)	$ (4,797)	(362)%
Deferred	$ 619	$ (2,321)	$ 2,940	127 %

We are subject to federal and state income taxes and the Texas franchise tax. The income tax (expense) benefit for the year ended December 31, 2022 is attributed to Texas franchise tax, due to a full valuation allowance recorded against the federal and Oklahoma deferred tax assets.

If we were to experience an "ownership change" as determined under Section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with net operating losses ("NOL carryforwards") arising prior to the ownership change would be limited. As of December 31, 2022, no such ownership change has occurred.

With the rise in oil prices and the addition of oily, high-margin inventory, we have seen positive indications that we will use our NOLs. We utilized $281.6 million of our NOLs on our 2021 tax return and expect to utilize a comparable amount on our 2022 tax return. However, as of December 31, 2022, we believe it is more likely than not that a portion of the NOL carryforwards are not fully realizable. We continue to consider new evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance is needed. Such consideration includes projected future cash flows from our oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2022, and our ability to capitalize intangible drilling costs, rather than expensing these costs and future projections of Oklahoma sourced income. Significant items of objective negative evidence considered were the cumulative historical three-year pre-tax loss and a net deferred tax asset position at December 31, 2022.

We currently believe it is reasonably possible we could achieve a three-year cumulative level of profitability within the next 12 months, which would enhance our ability to conclude that it is more likely than not that the deferred tax assets would be

realized and support a release of the valuation allowance. However, the exact timing and amount of the release is unknown at this time. As long as we continue to conclude that the valuation allowance recorded against our net deferred tax assets is necessary, we will not have significant deferred income tax expense or benefit. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income.

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. During the year ended December 31, 2022, we have utilized our cash flows to fund the repurchase of portions of our senior unsecured notes and our share repurchase program. For additional discussion of the repurchase of our senior unsecured notes and our share repurchase program, see Notes 7 and 8, respectively to our consolidated financial statements included elsewhere in this Annual Report.

We continually seek to maintain a financial profile that provides operational flexibility and monitor the markets to 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 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 will, from time to time, enter into interest rate derivative swaps to hedge interest rate risk associated with our debt under the Senior Secured Credit Facility. 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. As of December 31, 2022, the Company has not entered into any interest rate derivative swaps, and therefore our outstanding debt balance under our Senior Secured Credit Facility is subject to interest rate fluctuations. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below. See Notes 11 and 18 to our consolidated financial statements included elsewhere in this Annual Report for discussion of our open commodity positions.

As of December 31, 2022, we had cash and cash equivalents of $44.4 million and available capacity under the Senior Secured Credit Facility of $930.0 million, resulting in total liquidity of $974.4 million. As of February 17, 2023, we had cash and cash equivalents of $15.6 million and available capacity under the Senior Secured Credit Facility of $865.0 million, resulting in total liquidity of $880.6 million. We believe that our operating cash flows and the aforementioned liquidity sources provide us with sufficient liquidity and financial resources to manage our cash needs and contractual obligations, to 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.

Cash requirements for known contractual and other obligations

The following table presents significant cash requirements for known contractual and other obligations as of December 31, 2022:

(in thousands)	Short-term	Long-term	Total
Senior unsecured notes	$ 96,803	$ 1,394,575	$ 1,491,378
Senior Secured Credit Facility	—	70,000	70,000
Asset retirement obligations	3,715	70,366	74,081
Firm transportation commitments	17,555	57,043	74,598
Operating lease commitments	16,467	10,153	26,620
Total	$ 134,540	$ 1,602,137	$ 1,736,677

We expect to satisfy our short-term contractual and other obligations with cash flows from operations. See Notes 2, 5, 7, 15 and 18 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our known contractual and other obligations.

Cash flows

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

	Years ended December 31,		2022 compared to 2021	
(in thousands)	2022	2021	Change ($)	Change (%)
Net cash provided by operating activities	$ 829,620	$ 496,671	$ 332,949	67 %
Net cash used in investing activities	(475,952)	(796,811)	320,859	40 %
Net cash (used in) provided by financing activities	(366,031)	308,181	(674,212)	(219)%
Net (decrease) increase in cash and cash equivalents	$ (12,363)	$ 8,041	$ (20,404)	(254)%

Cash flows from operating activities

Net cash provided by operating activities increased during the year ended December 31, 2022, compared to 2021. Notable cash changes include (i) an increase in total oil, NGL and natural gas sales revenues of $647.2 million, (ii) a decrease of $174.3 million due to changes in net settlements received for matured, net of premiums paid, mainly due to increases in commodity prices and (iii) a decrease of $16.4 million due to net changes in operating assets and liabilities. Other significant changes include an increase in lease operating expense and production and ad valorem taxes. The increase in total oil, NGL and natural gas sales revenues is due to a 55% increase in average sales price per BOE as well as a 19% increase in oil 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. 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 decreased during the year ended December 31, 2022, compared to 2021, mainly due to (i) a decrease in acquisitions of oil and natural gas properties and (ii) an increase in capital expenditures, which includes the effects of inflationary pressures. Such items are partially offset by a decrease in proceeds from the sale of capital assets, which includes proceeds of $106.5 million for 2022 related to the sale of the Company's working interests in certain specified

non-operated oil and gas properties. 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.

Expected capital expenditures

We currently expect capital expenditures for 2023 to be in the approximate range of $625.0 million to $675.0 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,		2022 compared to 2021	
(in thousands)	**2022**	**2021**	**Change ($)**	**Change (%)**
Oil and natural gas properties[1]	$ 566,831	$ 444,337	$ 122,494	28 %
Midstream service assets	1,595	2,842	(1,247)	(44)%
Other fixed assets	12,150	6,807	5,343	78 %
Total incurred capital expenditures, excluding non-budgeted acquisition costs	$ 580,576	$ 453,986	$ 126,590	28 %

(1) See Note 19 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, 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 was $308.2 million during the year ended December 31, 2021, compared to net cash used in financing activities of $366.0 million during the year ended December 31, 2022. In 2022, we began executing our strategy to return cash to shareholders through redemption of our senior unsecured notes and repurchasing our equity, which consisted of extinguishment of debt on our senior unsecured notes of $282.9 million and share repurchases of $37.3 million during the year ended December 31, 2022. Other notable 2022 activity includes (i) borrowings on our Senior Secured Credit Facility of $455.0 million, (ii) payments on our Senior Secured Credit Facility of $490.0 million and (iii) stock exchanged for tax withholding of $7.4 million. 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 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 to our consolidated financial statements included elsewhere in this Annual Report.

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, 2022, our Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") had a maximum credit amount of $2.0 billion, a borrowing base of $1.3 billion and an aggregate elected commitment of $1.0 billion, with $70.0 million outstanding, and was subject to an interest rate of 6.897%. 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, 2022 and 2021, we had no letters of credit outstanding and one letter of credit outstanding of $44.1 million, respectively under the Senior Secured Credit Facility.

See Notes 7 and 18 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, 2022:

(in millions, except for interest rates)	Principal	Interest rate
January 2025 Notes	$ 455.6	9.500 %
January 2028 Notes	300.3	10.125 %
July 2029 Notes	298.2	7.750 %
Total senior unsecured notes	$ 1,054.1	

During the year ended December 31, 2022, we repurchased a total of $284.8 million in aggregate principal amount of our senior unsecured notes. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of these repurchases.

Supplemental Guarantor information

As of December 31, 2022, approximately $1.1 billion of our senior unsecured notes remained outstanding. Our wholly-owned subsidiary Vital Midstream Services, LLC ("VMS") (the "Guarantor"), jointly and severally, and fully and unconditionally, guarantees the January 2025 Notes, January 2028 Notes and July 2029 Notes. On February 3, 2023, Garden City Minerals, LLC ("GCM"), our former other wholly-owned subsidiary, was merged with and into Vital Energy, Inc. and is therefore no longer a guarantor under any of our debt arrangements.

The guarantees are senior unsecured obligations of the 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 Guarantor are subject to certain Releases. The obligations of the 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 Guarantor may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Vital is not restricted from making investments in the Guarantor and the Guarantor is not restricted from making intercompany distributions to Vital.

The assets, liabilities and results of operations of the combined issuer and the Guarantor 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 Guarantor 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. Furthermore, these non-GAAP financial measures should not be considered in isolation or as a substitute for GAAP measures of liquidity or financial performance, but rather should be considered in conjunction with GAAP measures, such as net income or loss, operating income or loss or cash flows from operating activities.

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. 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)	**2022**	**2021**
Net cash provided by operating activities	$ 829,620	$ 496,671
Less:		
Change in current assets and liabilities, net	54,260	49,321
Change in noncurrent assets and liabilities, net	(25,157)	(3,807)
Cash flows from operating activities before changes in operating assets and liabilities, net	800,517	451,157
Less incurred capital expenditures, excluding non-budgeted acquisition costs:		
Oil and natural gas properties[(1)]	566,831	444,337
Midstream service assets[(1)]	1,595	2,842
Other fixed assets	12,150	6,807
Total incurred capital expenditures, excluding non-budgeted acquisition costs	580,576	453,986
Free Cash Flow (non-GAAP)	$ 219,941	$ (2,829)

(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; gains or losses on disposal of assets; mark-to-market on derivatives; premiums paid or received for commodity derivatives that matured during the period; accretion expense; 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 (GAAP) to Adjusted EBITDA (non-GAAP) for the periods presented:

	Years ended December 31,	
(in thousands)	**2022**	**2021**
Net income	$ 631,512	$ 145,008
Plus:		
Share-settled equity-based compensation, net	8,403	7,675
Depletion, depreciation and amortization	311,640	215,355
Impairment expense	40	1,613
Organizational restructuring expenses	10,420	9,800
(Gain) loss on disposal of assets, net	1,079	(84,551)
Mark-to-market on derivatives:		
Loss on derivatives, net	298,723	452,175
Settlements paid for matured derivatives, net	(486,753)	(320,868)
Settlements received for contingent consideration	2,457	—
Net premiums paid for commodity derivatives that matured during the period[(1)]	—	(41,553)
Accretion expense	3,879	4,233
Interest expense	125,121	113,385
Loss on extinguishment of debt, net	1,459	—
Income tax expense	5,502	3,645
Adjusted EBITDA (non-GAAP)	$ 913,482	$ 505,917

(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 and (ii) future cash flows from oil and natural gas properties.

There have been no material changes in our critical accounting estimates during the year ended December 31, 2022.

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 Note 19 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.

New accounting standards

There are no new accounting standards not yet adopted and meaningful to disclose as of December 31, 2022. Additionally, we did not adopt any new accounting standards during the year ended December 31, 2022.

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.

Commodity price exposure

Due to the inherent volatility in oil, NGL and natural gas prices and the sometimes wide pricing differentials 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 positions are largely determined by the relevant forward commodity price curves of the indexes associated with our open derivative positions. The following table provides a sensitivity analysis of the projected incremental effect on income or loss before income taxes of a hypothetical 10% change in the relevant forward commodity price curves of the indexes associated with our open commodity positions as of December 31, 2022:

(in thousands)	As of December 31, 2022	
Commodity derivative asset position	$	16,433
Impact of a 10% increase in forward commodity prices	$	(27,299)
Impact of a 10% decrease in forward commodity prices	$	25,878

See Notes 2, 11, 12 and 18 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our commodity derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our senior unsecured notes bear interest at fixed rates. The interest rate on our Senior Secured Credit Facility as of December 31, 2022 was 6.897%. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our debt. The interest rate on borrowings may be based on an alternate base rate or term secured overnight financing rate ("Term SOFR"), at our option. Interest on alternate base rate loans is equal to the sum of (a) the highest of (i) the "prime rate" (as publically announced by Wells Fargo Bank, N.A.) in effect on such day, (ii) the federal funds effective rate in effect on such day plus 0.5% and (iii) the Adjusted Term SOFR (as defined in our Senior Secured Credit Facility) for a one-month tenor in effect on such a day plus 1% and (b) the applicable margin. Interest on Term SOFR loans is equal to the sum of (a)(i) the Term SOFR (as defined in our Senior Secured Credit Facility) rate for such period plus (ii) the Term SOFR Adjustment (as defined in our Senior Secured Credit Facility) of 0.1% (in the case of clause (a), subject to a floor of 0%) plus (b) the applicable margin. The applicable margin varies form 1.5% to 2.5% on alternate base rate borrowings and from 2.5% to 3.5% on Term SOFR borrowings, in each case, depending on our utilization ratio. At December 31, 2022, the applicable margin on our borrowings were 1.5% for alternate base rate borrowings and 2.5% for Term SOFR borrowings.

See Notes 7, 12 and 18 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our debt.

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 11, 12 and 18 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, 2022, 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, 2022.

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.

Ernst & Young 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, 2022. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2022, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Vital Energy, Inc.

Opinion on internal control over financial reporting

We have audited Vital Energy, Inc.'s internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Vital Energy, Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2022 consolidated financial statements of the Company and our report dated February 22, 2023 expressed an unqualified opinion thereon.

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/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2023

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

On June 3, 2022, following the completion of a comprehensive evaluation process, our Audit Committee dismissed Grant Thornton LLP (“Grant Thornton”) and appointed Ernst & Young LLP (“EY”) as the Company’s independent registered public accounting firm for the fiscal year ending December 31, 2022. The change was effective immediately.

Grant Thornton’s audit report on the Company’s consolidated financial statements for the fiscal years ended December 31, 2021 and 2020 did not contain an adverse opinion or a disclaimer of opinion and was not qualified or modified as to uncertainty, audit scope or accounting principle.

During the fiscal years ended December 31, 2021 and 2020 and through the subsequent interim period ending June 3, 2022, there were (i) no disagreements (as that term is defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions) between the Company and Grant Thornton on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which, if not resolved to the satisfaction of Grant Thornton would have caused Grant Thornton to make reference to the subject matter thereof in connection with its reports on the consolidated financial statements of the Company for such years, and (ii) no “reportable events” (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

During the fiscal years ended December 31, 2021 and 2020 and through the subsequent interim period ending June 3, 2022, neither the Company, nor any party on behalf of the Company, consulted with EY with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of the audit opinion that might be rendered with respect to the Company’s consolidated financial statements, and no written report or oral advice was provided to the Company by EY that was an important factor considered by the Company in reaching a decision as to any accounting, auditing or financial reporting issue, or (ii) any matter that was subject to any disagreement (as that term is defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions) or a reportable event (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

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, 2022 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, 2022. Ernst & Young 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, 2022.

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, 2022.

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, 2022.

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, 2022.

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, 2022.

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 by and between Laredo Petroleum, Inc. and Northern Oil and Gas, Inc., dated as of August 16, 2022.	8-K	2.1	8/17/2022
2.3	Purchase and Sale Agreement by and between Vital Energy, Inc. and Driftwood Energy Operating, LLC, dated as of February 14, 2023.	8-K	2.1	2/15/2023
3.1	Amended and Restated Certificate of Incorporation of Vital Energy, 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 Vital Energy, Inc., dated as of June 1, 2020.	8-K	3.1	6/1/2020
3.3	Third Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Vital Energy, Inc., dated January 9, 2023.	8-K	3.1	1/9/2023
3.4	Certificate of Ownership and Merger, dated as of December 30, 2013.	8-K	3.1	1/6/2014
3.5	Fourth Amended and Restated Bylaws of Vital Energy, Inc., adopted January 9, 2023.	8-K	3.2	1/9/2023
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
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

Exhibit	Description	Incorporated by reference (File No. 001-35380, unless otherwise indicated) Form	Exhibit	Filling Date
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	Eighth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of April 13, 2022, 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	4/19/2022
10.10	Ninth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of August 30, 2022, 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	8/30/2022
10.11	Tenth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of November 1, 2022, 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	11/3/2022
10.12	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
10.13	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
10.14#*	Vital Energy, Inc. Omnibus Equity Incentive Plan, as amended and restated as of January 9, 2023.			
10.15#*	Vital Energy, Inc. Change in Control Executive Severance Plan, as last amended January 9, 2023.			
10.16#*	Vital Energy, Inc. Executive Severance Plan, as amended and restated as of January 9, 2023.			
10.17#	Offer Letter, dated April 17, 2019, between Laredo Petroleum, Inc. and Mr. Jason Pigott.	10-Q	10.3	5/2/2019
10.18#	Offer Letter, dated June 12, 2020, between Laredo Petroleum, Inc. and Mr. Bryan J. Lemmerman.	10-Q	10.3	8/6/2020
10.19#	Form of Stock Option Agreement.	8-K	10.3	5/25/2016
10.20#	Form of 2020 Performance Share Unit Award Agreement.	10-K	10.18	2/22/2021
10.21#	Form of 2021 Performance Share Unit Award Agreement.	10-Q	10.3	5/6/2021
10.22#	Form of 2022 Performance Share Unit Award Agreement.	10-Q	10.2	5/5/2022
10.23#	Form of 2022 Restricted Share Unit Award Agreement.	10-Q	10.3	5/5/2022
10.24#*	Form of 2023 Performance Share Unit Award Agreement.			
10.25#	Form of Outperformance Share Unit Award Agreement.	10-Q	10.8	8/1/2019
10.26#	Form of Restricted Stock Unit Agreement.	8-K	10.2	5/25/2016
10.27#	Form of Phantom Unit Agreement.	10-K	10.21	2/22/2021
21.1*	List of Subsidiaries.			
22.1*	List of Issuers and Guarantor Subsidiaries.			
23.1*	Consent of Ernst & Young LLP.			
23.2*	Consent of Grant Thornton LLP.			
23.3*	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.			

Exhibit	Description	Incorporated by reference (File No. 001-35380, unless otherwise indicated)		
		Form	Exhibit	Filling Date
101	The following financial information from Vital's Annual Report on Form 10-K for the year ended December 31, 2022, 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.

Item 16. Form 10-K Summary

None.

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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.

	Vital Energy, Inc.	
Date: February 22, 2023	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, 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)	2/22/2023
/s/ Bryan J. Lemmerman Bryan J. Lemmerman	Senior Vice President and Chief Financial Officer (principal financial officer)	2/22/2023
/s/ Jessica R. Wren Jessica R. Wren	Senior Director of Financial Accounting and SEC Reporting (principal accounting officer)	2/22/2023
/s/ William E. Albrecht William E. Albrecht	Chairman	2/22/2023
/s/ John Driver John Driver	Director	2/22/2023
/s/ Francis Powell Hawes Frances Powell Hawes	Director	2/22/2023
/s/ Jarvis V. Hollingsworth Jarvis V. Hollingsworth	Director	2/22/2023
/s/ Craig M. Jarchow Craig M. Jarchow	Director	2/22/2023
/s/ Shihab A. Kuran Shihab A. Kuran	Director	2/22/2023
/s/ Lisa M. Lambert Lisa M. Lambert	Director	2/22/2023
/s/ Lori A. Lancaster Lori A. Lancaster	Director	2/22/2023
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/22/2023

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Vital Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Vital Energy, Inc. (the Company) as of December 31, 2022, the related consolidated statements of operations, stockholders' equity and cash flows for the year ended December 31, 2022, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022, and the results of its operations and its cash flows for the year ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

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, 2022, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 22, 2023 expressed an unqualified opinion thereon.

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 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 the financial statements are free of material misstatement, whether due to error or fraud. Our audit 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 audit 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 audit provides 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 the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depreciation, Depletion, and Amortization (DD&A) of proved properties

Description of the Matter	At December 31, 2022, the carrying value of the Company's oil and natural gas properties was $2,283 million, and depreciation, depletion and amortization (DD&A) expense was $312 million for the year then ended. As described in Note 2, the Company follows the full cost method of accounting for its oil and gas properties. The cost of oil and natural gas properties, net is amortized using the unit-of-production method based on total proved oil, NGL and natural gas reserves, as estimated by the independent reserve engineers. Proved oil, NGL and natural gas reserves are those quantities of crude oil, natural gas liquids, and natural gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic and operating conditions. Significant judgment is required by the independent reserve engineers in interpreting the data used to estimate proved oil, NGL and natural gas reserves. Estimating reserves also requires the selection of inputs, including historical production, oil and gas price assumptions, and future operating and capital costs assumptions, among others. Because of the complexity in estimating oil, NGL and natural gas reserves, management used independent reserve engineers to prepare the proved oil, NGL and natural gas reserve estimates as of December 31, 2022. Auditing the Company's DD&A expense is complex because of the use of the work of the independent reserve engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil, NGL and natural gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls that address the risks of material misstatement relating to the DD&A expense calculation for oil and natural gas properties. This includes controls over the completeness and accuracy of the financial data used in estimating proved oil, NGL and natural gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's independent reserve engineers used to prepare the proved oil, NGL and natural gas reserve estimates. In addition, in assessing whether we can use the work of the independent reserve engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating oil, NGL and natural gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with SEC requirements. We also tested that the DD&A expense calculation is based on the appropriate proved oil, NGL and natural gas reserve amounts as estimated by the Company's independent reserve engineers.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2022.

Tulsa, OK
February 22, 2023

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Vital Energy, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheet of Vital Energy, Inc. (formerly known as Laredo Petroleum, Inc.) (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2021, the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2021, and 2020, 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 the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with 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 for our opinion.

/s/ GRANT THORNTON LLP

We served as the Company's auditor from 2007 to 2022.

Tulsa, Oklahoma
February 24, 2022

Consolidated balance sheets

(in thousands, except share data)	December 31, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 44,435	$ 56,798
Accounts receivable, net	163,369	151,807
Derivatives	24,670	4,346
Other current assets	13,317	22,906
Total current assets	245,791	235,857
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	9,554,706	8,968,668
Unevaluated properties not being depleted	46,430	170,033
Less: accumulated depletion and impairment	(7,318,399)	(7,019,670)
Oil and natural gas properties, net	2,282,737	2,119,031
Midstream service assets, net	85,156	96,528
Other fixed assets, net	42,647	34,590
Property and equipment, net	2,410,540	2,250,149
Derivatives	24,363	32,963
Operating lease right-of-use assets	23,047	11,514
Other noncurrent assets, net	22,373	21,341
Total assets	$ 2,726,114	$ 2,551,824
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 102,516	$ 71,386
Accrued capital expenditures	48,378	50,585
Undistributed revenue and royalties	160,023	117,920
Derivatives	5,960	179,809
Operating lease liabilities	15,449	7,742
Other current liabilities	82,950	99,471
Total current liabilities	415,276	526,913
Long-term debt, net	1,113,023	1,425,858
Asset retirement obligations	70,366	69,057
Operating lease liabilities	9,435	5,726
Other noncurrent liabilities	7,268	10,490
Total liabilities	1,615,368	2,038,044
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2022 and 2021	—	—
Common stock, $0.01 par value, 40,000,000 and 22,500,000 shares authorized, and 16,762,127 and 17,074,516 issued and outstanding as of December 31, 2022 and 2021, respectively	168	171
Additional paid-in capital	2,754,085	2,788,628
Accumulated deficit	(1,643,507)	(2,275,019)
Total stockholders' equity	1,110,746	513,780
Total liabilities and stockholders' equity	$ 2,726,114	$ 2,551,824

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, 2022	2021	2020
Revenues:			
Oil sales	$ 1,351,207	$ 805,448	$ 367,792
NGL sales	234,613	191,591	78,246
Natural gas sales	208,554	150,104	50,317
Sales of purchased oil	119,408	240,303	172,588
Other operating revenues	7,014	6,629	8,249
Total revenues	1,920,796	1,394,075	677,192
Costs and expenses:			
Lease operating expenses	173,983	101,994	82,020
Production and ad valorem taxes	110,997	68,742	33,050
Transportation and marketing expenses	53,692	47,916	49,927
Costs of purchased oil	122,118	251,061	194,862
General and administrative	68,082	62,801	50,534
Organizational restructuring expenses	10,420	9,800	4,200
Depletion, depreciation and amortization	311,640	215,355	217,101
Impairment expense	40	1,613	899,039
Other operating expenses, net	8,583	6,381	7,466
Total costs and expenses	859,555	765,663	1,538,199
Gain (loss) on disposal of assets, net	(1,079)	84,551	(963)
Operating income (expense)	1,060,162	712,963	(861,970)
Non-operating income (expense):			
Gain (loss) on derivatives, net	(298,723)	(452,175)	80,114
Interest expense	(125,121)	(113,385)	(105,009)
Gain (loss) extinguishment of debt, net	(1,459)	—	8,989
Other income (expense), net	2,155	1,250	(243)
Total non-operating expense, net	(423,148)	(564,310)	(16,149)
Income (loss) before income taxes	637,014	148,653	(878,119)
Income tax (expense) benefit:			
Current	(6,121)	(1,324)	—
Deferred	619	(2,321)	3,946
Total income tax (expense) benefit	(5,502)	(3,645)	3,946
Net income (loss)	$ 631,512	$ 145,008	$ (874,173)
Net income (loss) per common share:			
Basic	$ 37.88	$ 10.18	$ (74.92)
Diluted	$ 37.44	$ 10.03	$ (74.92)
Weighted-average common shares outstanding:			
Basic	16,672	14,240	11,668
Diluted	16,867	14,464	11,668

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

Consolidated statements of stockholders' equity

	Common stock		Additional paid-in capital	Treasury stock (at cost)		Accumulated deficit	Total
(in thousands)	Shares	Amount		Shares	Amount		
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
Restricted stock awards	255	3	(3)	—	—	—	—
Restricted stock forfeitures	(58)	(1)	1	—	—	—	—
Share repurchases	—	—	—	491	(37,290)	—	(37,290)
Stock exchanged for tax withholding	—	—	—	94	(7,442)	—	(7,442)
Retirement of treasury stock	(585)	(6)	(44,726)	(585)	44,732	—	—
Share-settled equity-based compensation	—	—	10,186	—	—	—	10,186
Performance share conversion	75	1	(1)	—	—	—	—
Net income	—	—	—	—	—	631,512	631,512
Balance, December 31, 2022	16,762	$ 168	$ 2,754,085	—	$ —	$ (1,643,507)	$ 1,110,746

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

Consolidated statements of cash flows

(in thousands)	Years ended December 31, 2022	2021	2020
Cash flows from operating activities:			
Net income (loss)	$ 631,512	$ 145,008	$ (874,173)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Share-settled equity-based compensation, net	8,403	7,675	8,217
Depletion, depreciation and amortization	311,640	215,355	217,101
Impairment expense	40	1,613	899,039
(Gain) loss on disposal of assets, net	1,079	(84,551)	963
Mark-to-market on derivatives:			
(Gain) loss on derivatives, net	298,723	452,175	(80,114)
Settlements (paid) received for matured derivatives, net	(486,173)	(320,868)	228,221
Settlements received for early-terminated commodity derivatives, net	—	—	6,340
Premiums received (paid) for commodity derivatives	—	9,041	(51,070)
Amortization of debt issuance costs	6,338	5,146	4,321
Amortization of operating lease right-of-use assets	22,621	13,609	13,070
(Gain) loss on extinguishment of debt, net	1,459	—	(8,989)
Deferred income tax (benefit) expense	(619)	2,321	(3,946)
Other, net	5,494	4,633	4,369
Changes in operating assets and liabilities:			
Accounts receivable, net	(9,226)	(87,831)	21,117
Other current assets	8,370	(8,767)	6,275
Other noncurrent assets, net	1,837	(8,782)	(6,768)
Accounts payable and accrued liabilities	31,534	31,387	(2,242)
Undistributed revenue and royalties	42,085	81,201	(8,395)
Other current liabilities	(18,503)	33,331	19,944
Other noncurrent liabilities	(26,994)	4,975	(9,890)
Net cash provided by operating activities	829,620	496,671	383,390
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties, net	(5,581)	(763,411)	(35,786)
Capital expenditures:			
Oil and natural gas properties	(566,989)	(418,362)	(347,359)
Midstream service assets	(1,436)	(2,849)	(3,171)
Other fixed assets	(12,711)	(5,931)	(4,259)
Proceeds from dispositions of capital assets, net of selling costs	108,888	393,742	1,337
Settlements received for contingent consideration	1,877	—	—
Net cash used in investing activities	(475,952)	(796,811)	(389,238)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	455,000	570,000	80,000
Payments on Senior Secured Credit Facility	(490,000)	(720,000)	(200,000)
Issuance of January 2025 Notes and January 2028 Notes	—	—	1,000,000
Issuance of July 2029 Notes	—	400,000	—
Extinguishment of debt	(282,902)	—	(846,994)
Proceeds from issuance of common stock, net of offering costs	—	72,492	—
Share repurchases	(37,290)	—	—
Stock exchanged for tax withholding	(7,442)	(2,596)	(779)
Payments for debt issuance costs	(1,938)	(14,686)	(18,479)
Other, net	(1,459)	2,971	—
Net cash (used in) provided by financing activities	(366,031)	308,181	13,748
Net (decrease) increase in cash and cash equivalents	(12,363)	8,041	7,900
Cash and cash equivalents, beginning of period	56,798	48,757	40,857
Cash and cash equivalents, end of period	$ 44,435	$ 56,798	$ 48,757

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

Notes to the consolidated financial statements

Note 1 Organization

Vital Energy, Inc. ("Vital" or the "Company"), together with its wholly-owned subsidiaries, is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties in the Permian Basin of West Texas. The Company has identified one operating segment: exploration and production. In these notes, the "Company" refers to Vital and its subsidiaries 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

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.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. There was no impact on previously reported total assets, total liabilities, net income (loss) or stockholders' equity for the periods presented.

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) income taxes, (vi) fair values of assets acquired and liabilities assumed in an acquisition, (vii) fair values of derivatives and (viii) 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.

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.

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, 2022	December 31, 2021
Oil, NGL and natural gas sales[(1)]	$ 111,260	$ 135,560
Joint operations, net[(2)]	35,801	11,491
Other	16,308	4,756
Total accounts receivable, net	$ 163,369	$ 151,807

(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, 2022 and 2021. 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.

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 11 and 12 for additional discussion of derivatives and their fair value measurement on a recurring basis, respectively.

Other current assets and liabilities

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

(in thousands)	December 31, 2022	December 31, 2021
Prepaid expenses and other	$ 7,247	$ 12,746
Inventory	6,070	10,160
Total other current assets	$ 13,317	$ 22,906

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

(in thousands)	December 31, 2022	December 31, 2021
Accrued interest payable	$ 43,984	$ 56,468
Accrued compensation and benefits	20,000	14,434
Other liabilities	18,966	28,569
Total other current liabilities	$ 82,950	$ 99,471

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 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.

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. Unless implicitly defined, the Company determines the present value of future lease payments using an estimated incremental borrowing rate.

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 2026. 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.

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.

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

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 12 for discussion of the Company's inventory impairments.

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 for additional discussion of the Company's debt issuance costs.

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 and related facilities 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 presents changes to the Company's asset retirement obligations liability for the periods presented:

	Years ended December 31,	
(in thousands)	2022	2021
Liability at beginning of year	$ 72,003	$ 68,326
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	362	14,610
Accretion expense(1)	3,879	4,233
Liabilities settled due to plugging and abandonment or removed due to sale	(2,163)	(15,186)
Revision of estimates	—	20
Liability at end of year	74,081	72,003
Less: current asset retirement obligations(2)	3,715	2,946
Non-current asset retirement obligations	$ 70,366	$ 69,057

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

(2) Current asset retirement obligations is included in "Other current liabilities" on the consolidated balance sheets.

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 Inventory in Note 2 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 12 for further discussion of fair value measurements.

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.

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.

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 applicable GAAP, 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. When 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 GAAP. The following table presents the net effect of these transactions for the periods presented:

	Years ended December 31,		
(in thousands)	**2022**	**2021**	**2020**
Sales of purchased oil inventory	$ 104,403	$ 327,839	$ 17,026
Purchased oil inventory	104,039	326,625	16,918
Net effect on earnings[(1)]	$ 364	$ 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.

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 under applicable GAAP. 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 under applicable GAAP 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, the Company has utilized the practical expedient under applicable GAAP 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 these 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 contract liability balances.

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, 2022, 2021 and 2020, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

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 for further discussion of the Company's Equity Incentive Plan.

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, 2022 or 2021. See Note 13 for additional information regarding the Company's income taxes.

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, 2022	2021	2020
Supplemental cash flow information:			
Cash paid for interest, net of $3,872, $5,866 and $3,019 of capitalized interest, respectively(1)	$ 131,867	$ 94,867	$ 77,401
Supplemental non-cash operating information:			
Right-of-use assets obtained in exchange for operating lease liabilities(2)	$ 34,532	$ 7,742	$ 2,349
Supplemental non-cash investing information:			
Fair value of contingent consideration asset (liability) on transaction closing date(3)	$ —	$ 33,832	$ (225)
Change in accrued capital expenditures	$ (2,207)	$ 22,310	$ (8,053)
Capitalized asset retirement cost	$ 362	$ 14,610	$ 2,252

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

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

(3) See Note 4 for additional discussion of the Company's acquisitions and divestiture of oil and natural gas properties that include contingent considerations. See Note 12 for discussion of the quarterly remeasurement of the respective contingent considerations.

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, 2022. Additionally, the Company did not adopt any new ASUs during the year ended December 31, 2022.

Note 4 Acquisitions and divestitures

2022 Divestiture

On August 16, 2022, the Company entered into a purchase and sale agreement with Northern Oil and Gas, Inc. ("NOG"), pursuant to which the Company agreed to sell to NOG the Company’s working interests in certain specified non-operated oil and gas properties (the "NOG Working Interest Sale").

On October 3, 2022, the Company closed the NOG Working Interest Sale for an aggregate sales price of $106.5 million, inclusive of customary closing adjustments, subject to post-closing adjustments.

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 $210.1 million, comprised of (i) $135.3 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) $3.9 million in transaction related expenses, inclusive of 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	$ 135,323
Transaction costs	3,861
Total purchase price	$ 210,105

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	$ 143,021
Unevaluated properties	74,468
Revenue suspense liabilities assumed	(7,384)
Allocated purchase price	$ 210,105

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.

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 in Note 7) 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 11 and 12 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 $94.3 million, net of transaction expenses of $11.6 million, on the Company's consolidated statements of operations, inclusive of 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.

2020 Asset acquisitions

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.

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

Lease costs

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

(in thousands)	Years ended December 31, 2022	Years ended December 31, 2021
Operating lease costs[1]	$ 24,174	$ 15,894
Short-term lease costs[2]	110,442	83,471
Variable lease costs[3]	11,328	6,873
Sublease income	(990)	(1,057)
Total lease costs, net	$ 144,954	$ 105,181

(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.

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, 2022	Years ended December 31, 2021
Operating cash flows from operating leases	$ 3,892	$ 4,065
Investing cash flows from operating leases[1]	$ 20,398	$ 12,569

(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, 2022	December 31, 2021
Weighted-average remaining lease term	1.91 years	2.80 years
Weighted-average discount rate	5.84 %	7.41 %

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, 2022
2023	$ 16,467
2024	6,789
2025	1,350
2026	1,348
2027	666
Total minimum lease payments	26,620
Less: imputed interest	(1,736)
Present value of future minimum lease payments	$ 24,884

Other information

See Note 2 for disclosure of supplemental non-cash adjustments information related to operating leases and Note 18 for disclosure of significant leases not yet commenced as of December 31, 2022.

Note 6 Property and equipment

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)	2022	2021	2020
Capitalized employee-related costs	$ 17,026	$ 18,255	$ 18,954

See Note 19 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)	2022	2021	2020
Depletion expense of evaluated oil and natural gas properties	$ 298,259	$ 201,691	$ 203,492
Depletion expense per BOE sold	$ 9.92	$ 6.76	$ 6.34

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 2022 and 2021.

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

	December 31, 2022	December 31, 2021	December 31, 2020
Benchmark Prices:			
Oil ($/Bbl)	$ 90.15	$ 63.04	$ 36.04
NGL ($/Bbl)[(1)]	$ 41.77	$ 34.51	$ 16.63
Natural gas ($/MMBtu)	$ 5.20	$ 3.35	$ 1.21
Realized Prices:			
Oil ($/Bbl)	$ 96.21	$ 66.37	$ 37.69
NGL ($/Bbl)	$ 29.84	$ 22.90	$ 7.43
Natural gas ($/Mcf)	$ 4.24	$ 2.61	$ 0.79

(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)	2022	2021	2020
Full cost ceiling impairment expense	$ —	$ —	$ 889,453

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. 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, 2022	December 31, 2021
Midstream service assets	$ 151,157	$ 165,232
Less accumulated depreciation and impairment	(66,001)	(68,704)
Total midstream service assets, net	$ 85,156	$ 96,528

During the year ended December 31, 2022, the Company retired $15.6 million in midstream service assets, resulting in the removal of $11.4 million in accumulated depreciation and the recognition of an associated loss of $4.2 million. 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.

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, 2022	December 31, 2021
Computer hardware and software	$ 21,758	$ 15,039
Vehicles	7,934	9,072
Leasehold improvements	7,136	7,136
Buildings	7,039	7,039
Other	6,087	5,095
Depreciable total	49,954	43,381
Less accumulated depreciation and amortization	(30,382)	(27,692)
Depreciable total, net	19,572	15,689
Land	23,075	18,901
Total other fixed assets, net	$ 42,647	$ 34,590

Note 7 Debt

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, 2022			December 31, 2021		
(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	455,628	(3,297)	452,331	577,913	(6,345)	571,568
January 2028 Notes	300,309	(3,478)	296,831	361,044	(5,024)	356,020
July 2029 Notes	298,214	(4,353)	293,861	400,000	(6,730)	393,270
Senior Secured Credit Facility(1)	70,000	—	70,000	105,000	—	105,000
Total	$ 1,124,151	$ (11,128)	$ 1,113,023	$ 1,443,957	$ (18,099)	$ 1,425,858

(1) Debt issuance costs, net related to the Senior Secured Credit Facility of $7.3 million and $8.1 million as of December 31, 2022 and 2021, respectively, are included in "Other noncurrent assets, net" on the consolidated balance sheets.

Senior unsecured notes repurchases

The following table presents the Company's repurchases of its senior unsecured notes under authorized bond purchase programs and the related gain or loss on extinguishment of debt during the period presented:

(in thousands)	Year ended December 31, 2022	Year ended December 31, 2021	Year ended December 31, 2020
January 2025 Notes	$ 122,285	$ —	$ 22,087
January 2028 Notes	60,735	—	38,956
January 2029 Notes	101,786	—	—
Total principal amount repurchased	$ 284,806	$ —	$ 61,043
Less:			
Consideration paid	$ 282,902	$ —	$ 38,139
Write off of debt issuance costs	3,363	—	595
Gain (loss) on extinguishment of debt, net[1]	$ (1,459)	$ —	$ 22,309

(1) Amounts are included in "Gain (loss) on extinguishment of debt, net" on the consolidated statements of operations.

Senior Secured Credit Facility

On April 13, 2022, the Company entered into the Eighth Amendment to the Senior Secured Credit Facility (the "Eighth Amendment"). The Eighth Amendment, among other things, (i) increased the borrowing base from $1.0 billion to $1.25 billion and the aggregate elected commitment from $725.0 million to $1.0 billion, (ii) increased, from closing through December 31, 2022, the $50.0 million bond buyback and distributions baskets to $250.0 million, subject to certain conditions, (iii) added an energy transition and technology commercialization investment basket of $25.0 million, subject to certain conditions, (iv) allows for the designation of unrestricted subsidiaries and (v) amended certain other provisions relating to certain commercial agreements and the administration of Loans, in each case, subject to the terms of the Eighth Amendment and the Senior Secured Credit Facility.

On August 30, 2022, the Company entered into the Ninth Amendment to the Senior Secured Credit Facility (the "Ninth Amendment"). The Ninth Amendment, among other things, (i) added additional capacity to making repurchases of the Company's common stock and (ii) clarified the conditions to making redemptions of the Company's debt.

On November 1, 2022, the Company entered into the Tenth Amendment to the Senior Secured Credit Facility (the "Tenth Amendment"). The Tenth Amendment, among other things, (i) increased the borrowing base from $1.25 billion to $1.3 billion, (ii) permitted additional senior note buybacks and other restricted payments, subject to certain conditions; and (iii) made technical changes to permit the Company to potentially incur term loans, subject to terms to be agreed with lenders making such term loans, in addition to revolving loans, in each case, subject to the terms of the Tenth Amendment and the Senior Secured Credit Facility.

As of December 31, 2022, 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 and an aggregate elected commitment of $1.3 billion and $1.0 billion, respectively, with a $70.0 million balance outstanding, and was subject to an interest rate of 6.897%. 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 SOFR advances under the facility bear interest, at the Company's election, at the end of one-month, three-month or six-month interest periods (and in the case of six-month interest periods, every three months prior to the end of such interest period) at a Secured Overnight Financing Rate ("SOFR") 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. Vital 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 Vital 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 $50.0 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 not greater than 3.50 to 1.00. The Company was in compliance with these covenants as of December 31, 2022 and 2021, as then in effect. 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, the Company had one letter of credit outstanding of $44.1 million under the Senior Secured Credit Facility. No letters of credit were outstanding under the Senior Secured Credit Facility as of December 31, 2022.

See Note 18 for discussion of a borrowing and repayment on the Senior Secured Credit Facility subsequent to December 31, 2022.

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 Company was in compliance with these covenants as of December 31, 2022 and 2021.

As of December 31, 2022, the July 2029 Notes are fully and unconditionally guaranteed on a senior unsecured basis by VMS, 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"). On February 3, 2023, GCM was merged with and into Vital Energy, Inc. and is therefore no longer a guarantor under any of the Company's debt arrangements.

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.

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 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 Company was in compliance with these covenants as of December 31, 2022 and 2021.

As of December 31, 2022, the January 2025 Notes and January 2028 Notes are fully and unconditionally guaranteed on a senior unsecured basis by VMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On February 3, 2023, GCM was merged with and into Vital Energy, Inc. and is therefore no longer a guarantor under any of the Company's debt arrangements.

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 cash tender offers and consent solicitations for any or all of the Company's outstanding 5 5/8% senior unsecured notes due 2022 and 6 1/4% senior unsecured notes due 2023 (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.

January 2022 Notes and March 2023 Notes

In January 2020, the Company commenced cash tender offers and consent solicitations for any or all of the $450.0 million and $350.0 million aggregate principle amounts outstanding on the previously disclosed January 2022 Notes and March 2023 Notes, respectively (collectively, the "Tender Offers"). During the first quarter of 2020, the Company settled the Tender Offers for aggregate principle outstanding amounts of $728.3 million for consideration for tender offers and early tender premiums of $735.7 million, plus accrued and unpaid interest. Following the settlement of the tender offers, the Company redeemed the remaining $71.7 million outstanding balances of both notes. 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 which is included in "Gain (loss) on extinguishment of debt, net" on the consolidated statements of operations.

Interest expense

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

	Years ended December 31,		
(in thousands)	**2022**	**2021**	**2020**
Interest expense on borrowings	$ 123,255	$ 114,800	$ 104,320
Amortization of debt issuance costs and other adjustments	5,738	4,451	3,708
Less capitalized interest	3,872	5,866	3,019
Total interest expense	$ 125,121	$ 113,385	$ 105,009

Note 8 Stockholders' equity

Authorized shares increase

On May 26, 2022, upon recommendation of the Company's board of directors, stockholders approved an amendment to the Company's Amended and Restated Certificate of Incorporation to increase the number of authorized shares of its common stock from 22,500,000 shares to 40,000,000 shares.

Share repurchase program

On May 31, 2022, the Company's board of directors authorized a $200.0 million share repurchase program. The repurchase program commenced in May 2022 and expires in May 2024. Share repurchases under the program may be made through a variety of methods, which may include open market purchases, including under plans complying with Rule 10b5-1 of the Exchange Act, and privately negotiated transactions. The timing and actual number of share repurchases will depend upon several factors, including market conditions, business conditions, the trading price of the Company's common stock and the nature of other investment opportunities available to the Company.

The following table presents the Company's open market repurchases of its common stock during the periods presented:

(in thousands, except for share and share price data)	Year ended December 31, 2022
Shares of Company common stock repurchased	490,536
Average share price[(1)]	$ 76.02
Total	$ 37,290

(1) Average share price includes any commissions paid to repurchase stock.

All shares were retired upon repurchase. No shares were repurchased during the years ended December 31, 2021 and 2020.

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 had 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.

Reverse stock split and reduction of authorized shares

On June 1, 2020, the amendment to the Company's amended and restated 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 reduction of the number of authorized shares of common stock 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 for discussion of the Vital Energy, Inc. Omnibus Equity Incentive Plan (the "Equity Incentive Plan"), that proportionately reduced the number of shares that may be granted.

Note 9 Compensation plans

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 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.

At December 31, 2022, the Company had outstanding restricted stock awards, performance share awards, performance unit awards, phantom unit awards and an immaterial amount of stock option awards.

Equity Awards

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the consolidated financial statements. 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.

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, which begins at the start of the calendar year in which the award is granted.

For performance share awards granted in 2022, the market criteria consists of: (i) annual relative total shareholder return comparing the Company's shareholder return to the shareholder return of the exploration and production companies listed in the Russell 2000 Index and (ii) annual absolute total shareholder return. The performance criteria for these awards consists of: (i) earnings before interest, taxes, depreciation, amortization and exploration expense and three-year total debt reduction, (ii) growth in inventory and (iii) emissions reduction targets. Any shares earned 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 225%.

For performance share awards granted in 2019, the 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"). Potential payout of these awards ranged from 0% to 200%. In the first quarter of 2022, following the completion of the requisite service period and achievement of certain market and performance criteria, these shares were issued at 107% payout.

Equity award activity

The following table presents activity for equity compensation awards for the year ended December 31, 2022:

(in thousands)	Restricted Stock Awards	Weighted-average grant-date fair value (per share)	Stock Option Awards	Weighted-average exercise price (per share)	Performance Share Awards	Weighted-average grant-date fair value (per share)
Outstanding as of December 31, 2021	350	$35.57	7	$275.88	72	$64.74
Granted	255	$67.54	—		62	$89.76
Forfeited	(58)	$46.75	—		(16)	$88.28
Vested(1)(2)	(185)	$42.30	—		(70)	$64.53
Expired or canceled	—		(4)	$313.12	—	
Outstanding as of December 31, 2022(3)	362	$52.90	3	$235.08	48	$89.76

(1) The aggregate intrinsic value of vested restricted stock awards for the year ended December 31, 2022 was $14.6 million.

(2) 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 satisfied, resulted in a 107% payout. As such, the granted awards vested and were converted into 75,107 shares of the Company's common stock during the year ended December 31, 2022 based on this 107% payout.

(3) The vested and exercisable stock option awards as of December 31, 2022 had no intrinsic value.

As of December 31, 2022, total unrecognized cost related to equity compensation awards was $16.0 million, which will be settled in shares. Such cost will be recognized on a straight-line basis over an expected weighted-average period of 2.02 years.

Equity-based liability awards

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 each performance unit award, the three-year performance period begins at the start of the calendar year in which the award is granted.

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 and (ii) annual absolute total shareholder 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. The performance period for the performance unit awards granted March 5, 2020 ended December 31, 2022. As their market and performance criteria were fully satisfied, resulting in a 151% payout, the granted awards will be paid in cash during the first quarter of 2023.

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.

Equity-based liability award activity

The following table presents activity for equity-based liability awards for the year ended December 31, 2022:

(in thousands)	Performance Unit Awards	Phantom Unit Awards
Outstanding as of December 31, 2021	209	33
Forfeited	(59)	—
Vested[(1)]	—	(15)
Outstanding as of December 31, 2022	150	18

(1) On March 1, 2022 and March 5, 2022, the vested phantom unit awards were settled and paid out in cash at a fair value of $76.60 and $83.00 based on the Company's closing stock price on the respective vesting dates.

The fair value per unit of outstanding phantom unit awards as of December 31, 2022 was $51.42.

As of December 31, 2022, total unrecognized cost related to equity-based liability awards was $3.1 million, which will be settled in cash rather than shares. Such cost will be recognized on a straight-line basis over an expected weighted-average period of 1.05 years.

Fair value assumptions

The Company utilizes the closing stock price on the grant date to determine the fair value of restricted stock awards.

The following table presents (i) the assumptions used to estimate the fair values per performance share or unit and (ii) the expense per performance share or unit, which is the fair value per performance share or unit adjusted for the estimated payout of the performance criteria, for the outstanding performance share and unit awards as of December 31, 2022 for the grant dates presented:

	Performance Share Awards	Performance Unit Awards
	February 22, 2022	March 9, 2021
Remaining performance period on grant date	2.86 years	n/a
Remaining performance period	n/a	1 year
Risk-free interest rate[(1)]	1.71 %	4.62 %
Dividend yield	— %	— %
Expected volatility[(2)]	119.25 %	79.77 %
Expense per performance share or unit as of December 31, 2022	$89.76	$79.85

(1) 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.

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

The performance unit awards granted on March 5, 2020 had a performance period of January 1, 2020 to December 31, 2022. As of December 31, 2022, their expense per performance unit was $78.92

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.

Equity-based compensation

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

(in thousands)	Years ended December 31, 2022	2021	2020
Equity awards:			
Restricted stock awards	$ 8,596	$ 7,594	$ 8,839
Performance share awards	1,590	1,657	2,719
Stock option awards	—	7	77
Total share-settled equity-based compensation, gross	$ 10,186	$ 9,258	$ 11,635
Less amounts capitalized	(1,783)	(1,583)	(3,418)
Total share-settled equity-based compensation, net	$ 8,403	$ 7,675	$ 8,217
Liability awards:			
Performance unit awards	$ 741	$ 7,480	$ 749
Phantom unit awards	1,186	1,238	404
Total cash-settled equity-based compensation, gross	$ 1,927	$ 8,718	$ 1,153
Less amounts capitalized	(272)	(365)	(163)
Total cash-settled equity-based compensation, net	$ 1,655	$ 8,353	$ 990
Total equity-based compensation, net	$ 10,058	$ 16,028	$ 9,207

See Note 17 for discussion of the Company's organizational restructurings and the related equity-based compensation reversals during the years ended December 31, 2022, 2021 and 2020.

Note 10 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 equity-based compensation awards. See Note 9 for additional discussion of these awards. For the year ended December 31, 2020, all of these awards were anti-dilutive 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:

(in thousands, except for per share data)	Years ended December 31, 2022	2021	2020
Net income (loss)	$ 631,512	$ 145,008	$ (874,173)
Weighted-average common shares outstanding:			
Basic	16,672	14,240	11,668
Dilutive non-vested restricted stock awards	183	181	—
Dilutive non-vested performance share awards(1)	12	43	—
Diluted	16,867	14,464	11,668
Net income (loss) per common share:			
Basic	$ 37.88	$ 10.18	$ (74.92)
Diluted	$ 37.44	$ 10.03	$ (74.92)

(1) The dilutive effect of the non-vested performance shares for the year ended December 31, 2022 was calculated as of the end of the performance period on December 31, 2022.

Note 11 Derivatives

The Company has two types of derivative instruments as of December 31, 2022: (i) commodity derivatives and (ii) a contingent consideration derivative. In previous periods, the Company also engaged in an interest rate swap derivative, which concluded during the quarterly period ended June 30, 2022. See Notes (i) 2 for the Company's significant accounting policies for derivatives and presentation in the consolidated financial statements, (ii) 12 for fair value measurement of derivatives on a recurring basis and (iii) 18 for derivatives subsequent events.

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

(in thousands)	Years ended December 31, 2022	2021	2020
Commodity	$ (291,973)	$ (453,784)	$ 73,662
Contingent consideration	(6,764)	1,639	6,795
Interest rate	14	(30)	(343)
Gain (loss) on derivatives, net	$ (298,723)	$ (452,175)	$ 80,114

Commodity

Due to the inherent volatility in oil, NGL and natural gas prices and the sometimes wide pricing differentials 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. During the year ended December 31, 2022, the Company's derivatives were settled based on reported prices on commodity exchanges, with (i) oil derivatives settled based on WTI NYMEX 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.

The following table summarizes open commodity derivative positions as of December 31, 2022, for commodity derivatives that were entered into through December 31, 2022, for the settlement periods presented:

		Year 2023
Oil:		
WTI NYMEX - Collars:		
Volume (Bbl)		5,089,000
Weighted-average floor price ($/Bbl)	$	68.58
Weighted-average ceiling price ($/Bbl)	$	84.88
Natural gas:		
Henry Hub NYMEX - Collars:		
Volume (MMBtu)		25,550,000
Weighted-average floor price ($/MMBtu)	$	4.14
Weighted-average ceiling price ($/MMBtu)	$	8.43
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps:		
Volume (MMBtu)		25,550,000
Weighted-average differential ($/MMBtu)	$	(1.65)

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. As of December 31, 2022, the maximum remaining additional cash consideration of the contingent consideration was $88.9 million. The fair value of the Sixth Street Contingent Consideration was determined to be $26.6 million as of December 31, 2022 and $35.9 million as of December 31, 2021.

See Note 4 for further discussion of the Working Interest Sale associated with the Sixth Street Contingent Consideration.

Interest rate swap

In previous periods, the Company was engaged in 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 paid a fixed rate over the contract term for that portion. During the year ended December 31, 2022, the Company's interest rate swap derivative, which concluded during the quarterly period ended June 30, 2022, was settled based on LIBOR rates. By removing a portion of the interest rate volatility associated with anticipated outstanding debt, the Company intended to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

Note 12 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.

Fair value measurement on a recurring basis

For further discussion of the Company's derivatives, see Notes (i) 2 for the Company's significant accounting policies for derivatives, (ii) 11 for derivatives and (iii) 18 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, 2022					
(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	$ —	$ 35,586	$ —	$ 35,586	$ (13,193)	$ 22,393
Contingent consideration	—	—	2,277	2,277	—	2,277
Noncurrent:						
Contingent consideration	—	—	24,363	24,363	—	24,363
Liabilities:						
Current:						
Commodity	—	(19,153)	—	(19,153)	13,193	(5,960)
Net derivative asset positions	$ —	$ 16,433	$ 26,640	$ 43,073	$ —	$ 43,073

	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	$ —	$ 21,671	$ —	$ 21,671	$ (21,671)	$ —
Contingent consideration	—	—	4,346	4,346	—	4,346
Noncurrent:						
Commodity	—	1,448	—	1,448	—	1,448
Contingent consideration	—	—	31,515	31,515	—	31,515
Liabilities:						
Current:						
Commodity	—	(201,428)	—	(201,428)	21,671	(179,757)
Interest rate	—	(52)	—	(52)	—	(52)
Net derivative asset (liability) positions	$ —	$(178,361)	$ 35,861	$(142,500)	$ —	$ (142,500)

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.

Contingent consideration

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, the Company remeasures contingent consideration with the change in fair values recognized in "Gain (loss) on derivatives, net" under "Non-operating income (expense)" on the consolidated statement of operations.

The following table summarizes the changes in contingent consideration derivatives classified as Level 3 measurements for the periods presented:

	Years ended December 31,		
(in thousands)	2022	2021	2020
Balance of Level 3 at beginning of year	$ 35,861	$ —	$ —
Sixth Street Contingent Consideration valuation as of Sixth Street Closing Date	—	33,832	—
Change in Sixth Street Contingent Consideration fair value	(11,678)	2,029	—
Settlements realized[(1)]	2,457	—	—
Balance of Level 3 at end of year	$ 26,640	$ 35,861	$ —

(1) For the year ended December 31, 2022, $1.9 million of realized settlements has been received and is included in "Settlements received for contingent consideration" in cash flows from investing activities on the consolidated statements of cash flows, and $0.6 million is a receivable at period end.

See Note 4 for further discussion of the Company's acquisitions and divestitures associated with the potential contingent consideration payments.

Interest rate swap

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.

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, 2022		December 31, 2021	
(in thousands)	Long-term debt	Fair value[(1)]	Long-term debt	Fair value[(1)]
January 2025 Notes	$ 455,628	$ 449,122	$ 577,913	$ 589,471
January 2028 Notes	300,309	292,846	361,044	378,578
July 2029 Notes	298,214	268,416	400,000	390,000
Senior Secured Credit Facility	70,000	69,945	105,000	105,040
Total	$ 1,124,151	$ 1,080,329	$ 1,443,957	$ 1,463,089

(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, 2022 and 2021. 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, 2022 and 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)	2022	2021	2020
Current income tax (expense) benefit:			
Federal	$ —	$ —	$ —
State	(6,121)	(1,324)	—
Deferred income tax (expense) benefit:			
Federal	—	—	—
State	619	(2,321)	3,946
Total income tax (expense) benefit	$ (5,502)	$ (3,645)	$ 3,946

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, 2022, 2021 and 2020 to pre-tax earnings as a result of the following:

	Years ended December 31,		
(in thousands)	2022	2021	2020
Income tax (expense) benefit computed by applying the statutory rate	$ (133,773)	$ (31,217)	$ 184,405
Change in deferred tax valuation allowance	144,480	45,717	(182,634)
Non-deductible equity-based compensation	(19,301)	(13,640)	—
State income tax and change in valuation allowance	8,058	(3,274)	2,903
Other items	(4,966)	(1,231)	(728)
Total income tax (expense) benefit	$ (5,502)	$ (3,645)	$ 3,946

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 as of the dates presented:

(in thousands)	December 31, 2022	December 31, 2021
Deferred tax assets:		
Net operating loss carryforward	$ 307,357	$ 445,426
Equity-based compensation	2,933	11,123
Derivatives	—	36,639
Other	1,110	3,227
Total deferred tax asset	311,400	496,415
Valuation allowance	(298,184)	(443,390)
Deferred tax assets, net of valuation allowance	13,216	53,025
Deferred tax liabilities:		
Oil and natural gas properties, midstream service assets and other fixed assets	(11,105)	(53,868)
Derivatives	(2,331)	—
Total deferred tax liabilities	(13,436)	(53,868)
Texas net deferred tax liability[1]	$ (220)	$ (843)

(1) The net deferred tax liability is included in "Other noncurrent liabilities" as of December 31, 2022 and 2021, respectively.

As of December 31, 2022, the Company had federal net operating loss carryforwards totaling $1.5 billion which expire between 2033 and 2037 and state of Oklahoma net operating loss carryforwards totaling $34.4 million that will begin expiring in 2032. Due to the passing of the Tax Act, $425.9 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. As of December 31, 2022, no ownership change has occurred.

Since September 30, 2015, the Company has recorded a full valuation allowance against its federal and Oklahoma net deferred tax position. As such, the Company's effective tax rate is 1%, due to the Texas franchise tax. The Company's effective tax rate is affected by changes in valuation allowances, recurring permanent differences and discrete items that may occur in any given year, but are not consistent from year to year. For the years ended December 31, 2022, 2021 and 2020, the Company's items of discrete income tax expense or benefit were not material.

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, 2022 and 2021, 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 projected future cash flows from its oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2022 and the Company's ability to capitalize intangible drilling costs, rather than expensing these costs and future projections of taxable income. Significant items of objective negative evidence considered were the cumulative historical three-year pre-tax loss and net deferred tax asset position. Such objective evidence limits the ability to consider other subjective evidence such as the Company's potential for future growth. Based on all the evidence available, the Company determined it was more likely than not that the net deferred tax assets were not realizable.

The Company files a single return. The Company's income tax returns for the years 2019 through 2022 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.

On August 16, 2022, the U.S. Inflation Reduction Act of 2022 (the "IRA") was signed into U.S. law. The IRA includes various tax provisions, including a 1% excise tax on stock repurchases made by publicly traded U.S. corporations and a 15% corporate alternative minimum tax that applies to certain corporations with adjusted financial statement income in excess of $1.0 billion. The Company continues to evaluate the IRA and its effect on our financial results and operating cash flows.

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 commodity derivatives. The Company places its cash and cash equivalents with high credit quality financial institutions. The Company currently uses commodity derivatives to hedge its exposure to commodity prices. 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 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 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 derivative counterparties is somewhat mitigated. The Company minimizes the credit risk in commodity derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into commodity 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, 2022, the Company had a net asset position of $16.4 million from the fair values of its open commodity derivative contracts. See "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" located elsewhere in this Annual Report and Notes 2, 11, 12 and 18 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 Note 2 for additional information regarding the Company's accounts receivable and revenue recognition.

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,		
	2022	2021	2020
Purchaser A[1]	33 %	29 %	33 %
Purchaser B[1]	18 %	14 %	n/a[2]
Purchaser C	17 %	24 %	24 %
Purchaser D[1]	n/a[2]	17 %	14 %
Purchaser E	n/a[2]	n/a[2]	10 %

(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,		
	2022	2021	2020
Purchaser A[1]	47 %	47 %	69 %
Purchaser B[1]	22 %	31 %	16 %
Purchaser C[1]	22 %	22 %	14 %

(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.

Note 15 Commitments and contingencies

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including those that arise from interpretation of federal, state and local laws and regulations affecting the oil and natural gas industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of the Company's current operations. The Company may not have insurance coverage for some of these proceedings and failure to comply with applicable laws and regulations can result in substantial penalties. While many of these matters involve inherent uncertainty, as of the date hereof, the Company believes that any such legal proceedings, if ultimately decided adversely, will not have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

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 $13.2 million, $4.4 million and $4.0 million during the years ended December 31, 2022, 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 $11.5 million and $4.7 million as of December 31, 2022 and 2021, respectively, and is included in "Accounts payable and accrued liabilities" on the consolidated balance sheets.

As of December 31, 2022, future firm sale and transportation commitments of $165.6 million are expected to be satisfied and, as such, are not recorded as a liability on the consolidated balance sheet.

Note 16 Related parties

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)	**2022**	**2021**	**2020**
Capital expenditures for oil and natural gas properties	$ 103,152	$ 69,670	$ 63,886

Note 17 Organizational restructurings

On August 24, 2022, the Company announced the departure of the Company's Senior Vice President and Chief Operating Officer. Their responsibilities were absorbed by other members of the Company's management team.

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.

In connection with each of these organizational restructurings, the Company incurred one-time charges comprised of compensation, tax, professional, outplacement and insurance-related expenses, which are recorded as "Organizational restructuring expenses" on the consolidated statements of operations. All equity-based compensation awards held by the affected employees were forfeited and the corresponding equity-based compensation was reversed. See Note 9 for additional information on the associated forfeiture activity for the years ended December 31, 2022, 2021 and 2020. The following table reflects the aggregate of gross equity-based compensation expense reversals in connection with the Company's respective organizational restructurings, which are included in "General and administrative" on the consolidated statements of operations, for the periods presented:

	Years ended December 31,		
(in thousands)	**2022**	**2021**	**2020**
Gross equity-based compensation expense reversals	$ (4,908)	$ (1,088)	$ (793)

Note 18 Subsequent events

2023 Acquisition

On February 14, 2023, the Company entered into a purchase and sale agreement with Driftwood Energy Operating, LLC (the "Seller"), pursuant to which the Company agreed to purchase (the "Driftwood Acquisition") Seller's oil and gas properties in the Midland Basin, including approximately 11,200 net acres located in Upton and Reagan Counties and related assets and contracts, for a purchase price of (i) $127.6 million of cash, subject to customary closing price adjustments, and (ii) 1,578,948 shares of the Company's common stock. The Company currently expects to fund the cash portion of the purchase price and related transaction costs with respect to the Driftwood Acquisition from cash on hand and borrowings under its Senior Secured Credit Facility.

Leases

As of December 31, 2022, the Company had significant obligations for leases not yet commenced related to a new corporate office and equipment for completions, which commenced subsequent to December 31, 2022. Future undiscounted lease payments related to the corporate office, which continue through 2033, total $24.5 million. Future undiscounted lease payments related to the equipment for completions, which continue through 2025, total $126.0 million.

Senior Secured Credit Facility

On January 9, 2023, January 13, 2023 and February 13, 2023, the Company borrowed an additional $15.0 million, $40.0 million and $40.0 million, respectively, and on January 23, 2023, the Company repaid $30.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $135.0 million as of February 17, 2023. See Note 7 for additional discussion of the Senior Secured Credit Facility.

Commodity derivatives

The following table summarizes the resulting open oil and natural gas derivative positions as of December 31, 2022, updated for the derivative transactions entered into from December 31, 2022 through February 17, 2023, for the settlement periods presented:

	Year 2023	Year 2024
Oil:		
WTI NYMEX - Collars:		
Volume (Bbl)	5,607,000	—
Weighted-average floor price ($/Bbl)	$ 68.71	$ —
Weighted-average ceiling price ($/Bbl)	$ 84.90	$ —
Natural gas:		
Henry Hub NYMEX - Collars:		
Volume (MMBtu)	25,550,000	—
Weighted-average floor price ($/MMBtu)	$ 4.14	$ —
Weighted-average ceiling price ($/MMBtu)	$ 8.43	$ —
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps:		
Volume (MMBtu)	38,350,000	3,660,000
Weighted-average differential ($/MMBtu)	$ (1.54)	$ (0.75)

See Note 11 for additional discussion regarding the Company's derivatives. There has been no other derivative activity subsequent to December 31, 2022.

Note 19 Supplemental oil, NGL and natural gas disclosures (unaudited)

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)	2022	2021	2020
Property acquisition costs:			
Evaluated	$ 8,295	$ 899,128	$ 11,368
Unevaluated	3,470	198,770	25,549
Exploration costs	26,384	33,482	17,337
Development costs	540,447	410,855	326,823
Total oil and natural gas properties incurred capital expenditures	$ 578,596	$ 1,542,235	$ 381,077

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, 2022	December 31, 2021
Gross capitalized costs:		
Evaluated properties	$ 9,554,706	$ 8,968,668
Unevaluated properties not being depleted	46,430	170,033
Total gross capitalized costs	9,601,136	9,138,701
Less accumulated depletion and impairment	(7,318,399)	(7,019,670)
Net capitalized costs	$ 2,282,737	$ 2,119,031

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2022, by year in which such costs were incurred:

(in thousands)	2022	2021	2020	2019 and prior	Total
Unevaluated properties not being depleted	$ 14,707	$ 29,705	$ 784	$ 1,234	$ 46,430

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.

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)	2022	2021	2020
Revenues:			
Oil, NGL and natural gas sales	$ 1,794,374	$ 1,147,143	$ 496,355
Production costs:			
Lease operating expenses	173,983	101,994	82,020
Production and ad valorem taxes	110,997	68,742	33,050
Transportation and marketing expenses	53,692	47,916	49,927
Total production costs	338,672	218,652	164,997
Other costs:			
Depletion	298,259	201,691	203,492
Accretion of asset retirement obligation	3,653	4,018	4,227
Impairment expense	—	—	889,453
Income tax expense[1]	11,538	14,456	—
Total other costs	313,450	220,165	1,097,172
Results of operations	$ 1,142,252	$ 708,326	$ (765,814)

(1) During each of the years ended December 31, 2022, 2021 and 2020, 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 was computed utilizing the Company's effective tax rate of 1% for the year ended December 31, 2022, 2% for the year ended December 31, 2021 and 0% for the year ended December 31, 2020, 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.

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, 2022, 2021 and 2020. In accordance with SEC regulations, the reserves as of December 31, 2022, 2021 and 2020 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 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, 2022, 2021 and 2020, all of which are located within the U.S.:

	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE[(1)]
Proved developed and undeveloped reserves:				
As of December 31, 2019	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)
As of December 31, 2020	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)
As of December 31, 2021	120,902	100,047	586,145	318,640
Revisions of previous estimates	(9,792)	(4,561)	(14,694)	(16,802)
Extensions, discoveries and other additions	21,351	7,162	33,767	34,141
Divestitures of reserves in place	(2,165)	(808)	(3,671)	(3,585)
Production	(13,838)	(8,028)	(49,259)	(30,076)
As of December 31, 2022	116,458	93,812	552,288	302,318
Proved developed reserves:				
December 31, 2019	52,711	90,861	600,334	243,628
December 31, 2020	51,751	96,251	633,503	253,586
December 31, 2021	70,727	78,908	494,476	232,048
December 31, 2022	70,333	75,156	464,567	222,917
Proved undeveloped reserves:				
December 31, 2019	25,928	11,337	74,903	49,749
December 31, 2020	16,008	4,671	23,781	24,642
December 31, 2021	50,175	21,139	91,669	86,592
December 31, 2022	46,125	18,656	87,721	79,401

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

The following discussion is for the year ended December 31, 2022. The Company's negative revision of 16,802 MBOE of previously estimated quantities consisted of (i) 9,531 MBOE of negative revisions from performance of proved developed producing wells, (ii) 1,837 MBOE of negative revisions from a decrease in previously estimated quantities of proved undeveloped locations, (iii) 4,351 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) 9,785 MBOE of negative revisions due to 16 proved undeveloped locations that were removed from the development plan. Extensions, discoveries and other additions of 34,141 MBOE consisted of (i) 3,850 MBOE that resulted from new wells drilled and (ii) 30,291 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 3,585 MBOE attributed to the divestment of non-operated properties in Howard County.

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 became 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.

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, 2022, 2021 and 2020 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, as such, the Company recorded non-cash full cost ceiling impairments totaling $889.5 million during the year ended December 31, 2020. No full cost ceiling impairment was recorded for the years ended December 31, 2022 and December 31, 2021. See Note 6 for discussion of the Benchmark Prices, Realized Prices and the 2020 full cost ceiling impairment 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)	2022	2021	2020
Future cash inflows	$16,343,468	$11,846,148	$ 3,824,104
Future production costs	(4,136,380)	(3,595,524)	(1,740,537)
Future development costs	(1,403,721)	(1,064,527)	(351,568)
Future income tax expenses	(1,587,677)	(774,461)	(20,076)
Future net cash flows	9,215,690	6,411,636	1,711,923
10% discount for estimated timing of cash flows	(4,461,114)	(2,986,324)	(697,069)
Standardized measure of discounted future net cash flows	$ 4,754,576	$ 3,425,312	$ 1,014,854

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)	2022	2021	2020
Standardized measure of discounted future net cash flows, beginning of year	$ 3,425,312	$ 1,014,854	$ 1,662,261
Changes in the year resulting from:			
Sales, less production costs	(1,468,946)	(934,440)	(331,358)
Revisions of previous quantity estimates	(99,512)	426,060	199
Extensions, discoveries and other additions	667,859	293,511	60,004
Net change in prices and production costs	2,565,963	1,572,662	(770,885)
Changes in estimated future development costs	(165,579)	134,091	64,146
Previously estimated development incurred capital expenditures during the period	260,475	169,376	186,261
Acquisitions of reserves in place	—	1,509,087	14,208
Divestitures of reserves in place	(96,222)	(369,601)	—
Accretion of discount	371,625	102,607	167,227
Net change in income taxes	(418,537)	(279,722)	(1,205)
Timing differences and other	(287,862)	(213,173)	(36,004)
Standardized measure of discounted future net cash flows, end of year	$ 4,754,576	$ 3,425,312	$ 1,014,854

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.