TALOS ENERGY


# 2023 Annual Report

**Talos Energy** is a leading independent offshore energy company focused on oil and gas exploration and production in the United States Gulf of Mexico and offshore Mexico. We leverage our deep technical expertise and extensive physical operating experience to successfully manage our Upstream business and consistently make attractive acquisitions with a commitment to safe and efficient operations, environmental responsibility, and community impact.

# HIGHLIGHTS

## KEY METRICS

**66.3**
**MBOE/D**
Average Daily Production[1]

**$951**
**MILLION**
Adjusted EBITDA[1][2]

**$734**
**MILLION**
Upstream Capital Expenditures[1][3]

## RESPONSIBILITY

**A**
**ESG RATING**
by MSCI, May 2023

**~30%**
**REDUCTION**
in Scope 1 GHG Emissions Intensity[4]

**~64%**
**REDUCTION**
in Scope 2 GHG Emissions[5]

## ABOUT TALOS

**>750**
**EMPLOYEES**[6]

**5th**
**LARGEST**
Operator in the Gulf of Mexico[5]

**4th**
**LARGEST**
Acreage Holder in the Gulf of Mexico[6]

(1) *Reflects Talos standalone for year ended December 31, 2023.*
(2) *Adjusted EBITDA is a non-GAAP measure. Please refer to the Talos Supplemental Reconciliation of non-GAAP Information in this Annual Report.*
(3) *Upstream Capital Investments include plugging and abandonment and settlement and decommissioning obligations.*
(4) *Reduction of Scope 1 GHG emissions intensity versus 2018 baseline calculated using combined 2022 data, Talos and pro forma EnVen.*
(5) *Scope 2 reduction is Talos only and versus 2018 baseline. EnVen did not calculate Scope 2 emissions prior to 2022.*
(6) *Reflects combined Talos and QuarterNorth. Operator data based on GOMSmart and BSEE utilizing 2022 reported figures. Acreage data per GOM-Cubed. Acreage figures as of December 31, 2023 pro forma for QuarterNorth acquisition.*

# LETTER TO OUR SHAREHOLDERS

2023 was an important year as we advance our goal of becoming a large-scale, offshore deepwater exploration and production company. Our team hit a steady stride as we approached year-end, completing the integration of the EnVen transaction, which added scale and diversity with high margin, oil-weighted assets, and ample infrastructure. We delivered a solid performance, both financially and operationally, giving Talos significant momentum in 2024 while remaining mindful of safe and efficient operations.

**Timothy S. Duncan**
President and Chief Executive Officer

Talos has a strong oil-weighted portfolio with a mission to supply the world with the affordable, secure, and reliable energy it needs today. Since our founding over a decade ago, we have continued to grow both through the drill bit and a prudent acquisition strategy, including our most recently completed purchase of QuarterNorth Energy Inc. (QuarterNorth), which closed in March 2024. Our numerous acquisitions have made us the fifth-largest operator in the Gulf of Mexico.

Talos is well-positioned to continue building value for our shareholders. We believe in our differentiated strategy of utilizing offshore infrastructure to develop oil-weighted prospects with shorter cycle times to first oil than historical offshore cycle times from initial investment to first production. We view this as a consistent and repeatable investment catalyst driving future value creation, enabling us to advance our long-term goal of becoming the next great offshore deepwater energy company. As an established leader in the U.S. Gulf of Mexico, we leverage our decades of technical experience in conventional oil and gas plays and deep understanding of the basin as an experienced offshore operator, which allows us to identify and execute highly economic drilling projects. We are able to capitalize on rapid and efficient tiebacks to our largely Talos-owned infrastructure, balancing a mix of high-margin infield development wells, nearfield exploitation, and extended exploration.

With our oil-weighted portfolio concentrated in the Gulf of Mexico, we can also boast having our operations in one of the lowest greenhouse gas (GHG) emission intensity environments, as compared to the global average outside of the U.S. and Canada.

Just as important to the execution of our strategy are the contributions of our talented people. Our commitment to safe and responsible energy production while fostering a diverse and inclusive environment is fundamental to Talos's continued achievements. We sincerely thank our team for their dedication and hard work in Talos's success. Talos is primed to deliver sustainable value creation for shareholders.

## OUR 2023 PERFORMANCE

In 2023, Talos delivered solid results and operational performance in many key assets supporting our strategy.

A significant manifestation of our infrastructure-led strategy was the safe startup of our Venice and Lime Rock deepwater discoveries near Talos's owned and operated Ram Powell platform ahead of schedule and above production expectations. These projects achieved an initial combined gross production rate of over 18,000 barrels of oil equivalent per day. This is the highest oil rate achieved in the Ram Powell facility in over fifteen years. We recognize this as a remarkable achievement. We are aiming for similar success with our Sunspear deepwater discovery nearby the Prince platform, where we unlocked new resources as announced last year.

We also announced exciting exploration partnerships near our Neptune asset and in the Green Canyon area with companies including Repsol, BP Exploration & Production Inc., and Chevron U.S.A. Inc., laying the groundwork for inventory expansion, consolidating leases, and adding acreage and prospects to bolster inventory.

In Mexico, we completed an important transaction with our world-class Zama asset, bringing in Grupo Carso, a diversified global conglomerate owned by Carlos Slim, as a marquee partner in our Talos Mexico subsidiary. This transaction will provide material proceeds that will further enable us to advance progress of the Zama field toward first production.

Our operational achievements enabled us to end the year with netback margins that are among the best in the industry, solid liquidity, and low leverage.

## OUR STRATEGIC PRIORITIES

Our strategic priorities are clear – free cash flow generation, moderate, sustainable growth, and balance sheet discipline.

Our QuarterNorth acquisition was an important next step toward our goal. On a pro forma basis for the closed QuarterNorth transaction, we have entered 2024 with more extensive, predominantly operated, oil-weighted deepwater assets and related infrastructure that will enhance our ability to consistently generate substantial free cash flow while expanding our portfolio of growth opportunities. We believe this transaction provides several catalysts beyond the underwritten economics, which is expected to present Talos with material potential upside. The integration of our companies is on track as we work to realize the valuable synergies we expect to generate by year-end 2024 from the combination.

Our strategic evolution continued with the sale of our Carbon Capture and Sequestration business (CCS) in March 2024, realizing a ~2.0x multiple on invested capital and an internal rate of return exceeding 100%. Having a strategy that allows for flexibility, balance, and growth enabled us to become a meaningful contributor in a decarbonization economy when we launched our CCS business in 2021 to complement our growing Upstream business. During our Talos Low Carbon Solutions capital raise, strong market interest provided the strategic option to fully monetize the business. With this divestiture, we are crystallizing value creation and providing an outstanding result for Talos shareholders while prioritizing cash flow generation and optimal capital allocation in our core Upstream business.

## OUR COMMITMENT TO SUSTAINABILITY

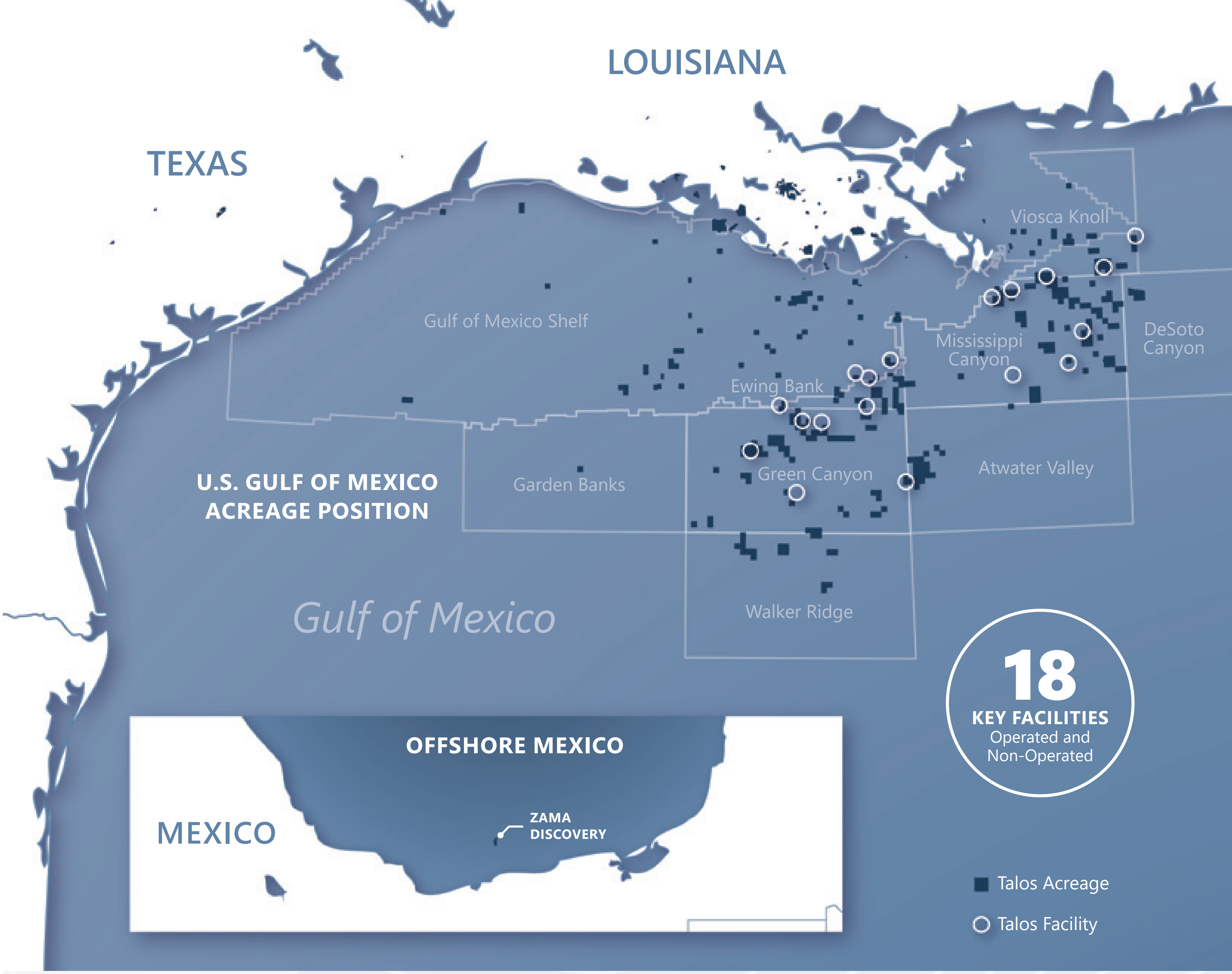
We continue to conduct our business in a way that enhances safety and minimizes environmental impacts, including meaningfully improving our emissions profile. In 2023, we announced a longer-term GHG emissions reduction target through 2030. We are proud to have achieved an “A” rating (on a AAA-CCC scale) in the MSCI ESG Ratings assessment. This is a noteworthy accomplishment made possible by our sustainability team’s hard work and dedication. In addition, we continued our active community support efforts and charitable contributions, breaking our record of employee contributions for various community charities. We were also pleased to be again named a Top Workplace by the Houston Chronicle for the eleventh consecutive year since our inception in 2012.

## LOOKING AHEAD

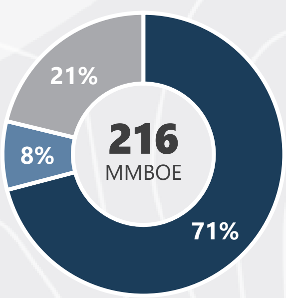
After closing two significant transactions over two years, our top priority in 2024 is showcasing the financial and operational benefits from our experienced integration and portfolio investments, including our Venice and Lime Rock wells and recently acquired Katmai discovery from QuarterNorth. Looking ahead, we expect to generate significant free cash flow, which we believe will result in one of the more competitive free cash flow yields in our industry. I’m pleased about the trajectory of our business and look forward to further delivering on our strategy, creating value for our shareholders, and bringing affordable, secure, and responsibly produced energy to the world.

On behalf of all of Talos, thank you for your continued investment and support.

**Timothy S. Duncan**
President and Chief Executive Officer

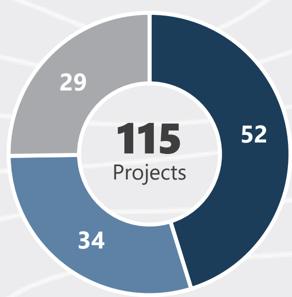



## PROVED RESERVES



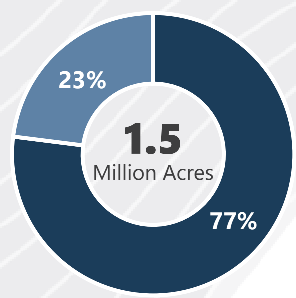

■ Oil ■ NGL ■ Gas

## PROJECT INVENTORY




■ Development ■ Exploitation ■ Exploration

## DEEPWATER FOOTPRINT




■ Deepwater ■ Shelf and Mexico

*Notes: Combined Talos and QuarterNorth based on acquisition closing in March 2024. Reserves volumes may fluctuate slightly based on economic limitations. SEC Reserves figures are presented inclusive of the plugging and abandonment obligations and before hedges, utilizing SEC pricing of $78.21 WTI per BBL of oil and $2.64 HH per MMBtu of natural gas. Acreage figures as of December 31, 2023, excluding CCS and pro forma for QuarterNorth. Primary Term includes all undeveloped acreage, including unitized, depth-severed acreage, etc. Total Net Acres of ~957,000. Mississippi Canyon includes Atwater Valley, DeSoto Canyon, Mississippi Canyon, and Viosca Knoll. Green Canyon includes Ewing Bank, Garden Banks, Green Canyon, Keathley Canyon and Walker Ridge.*

# We provide energy prosperity to improve lives.

# UNITED STATES SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

**(Mark One)**

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

**For the fiscal year ended December 31, 2023**

**OR**

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

**For the transition period from to**

**Commission File Number 001-38497**

**Talos Energy Inc.**
**(Exact name of Registrant as specified in its Charter)**

| | |
|---|---|
| **Delaware**<br>**(State or other jurisdiction of incorporation or organization)** | **82-3532642**<br>**(I.R.S. Employer Identification No.)** |
| **333 Clay Street, Suite 3300**<br>**Houston, TX**<br>**(Address of principal executive offices)** | **77002**<br>**(Zip Code)** |

**Registrant's telephone number, including area code: (713) 328-3000**

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

| Title of Each Class | Trading Symbol(s) | Name of Each Exchange on Which Registered |
|---|---|---|
| Common Stock | TALO | 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 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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the closing price of the shares of common stock on the New York Stock Exchange on June 30, 2023, was $1,493,763,437.

The number of shares of registrant's Common Stock outstanding as of February 21, 2024 was 158,632,597.

Portions of the registrant's definitive proxy statement relating to the 2024 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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## GLOSSARY

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

***Barrel or Bbl* —** One stock tank barrel, or 42 United States gallons liquid volume.

***Boe* —** One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

***BOEM*** — Bureau of Ocean Energy Management.

***BSEE*** — Bureau of Safety and Environmental Enforcement.

***Boepd* —** Barrels of oil equivalent per day.

***Btu* —** British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit.

***CCS* —** Carbon capture and sequestration.

***$CO_2$* —** Carbon dioxide.

***Completion* —** The installation of permanent equipment for the production of oil or natural gas.

***Deepwater* —** Water depths of more than 600 feet.

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

***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.

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

***Gross acres or gross wells* —** The total acres or wells in which the Company owns a working interest.

***MBbls* —** One thousand barrels of crude oil or other liquid hydrocarbons.

***MBblpd* —** One thousand barrels of crude oil or other liquid hydrocarbons per day.

***MBoe* —** One thousand barrels of oil equivalent.

***MBoepd* —** One thousand barrels of oil equivalent per day.

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

***Mcfpd* —** One thousand cubic feet of natural gas per day.

***MMBoe* —** One million barrels of oil equivalent.

***MMBtu* —** One million British thermal units.

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

***MMcfpd* —** One million cubic feet of natural gas per day.

***Net acres or net wells* —** The sum of the fractional working interests the Company owns in gross acres or gross wells.

***NGL* —** Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasoline.

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

***NYMEX Henry Hub* —** Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub index.

***OPEC* —** Organization of Petroleum Exporting Countries.

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

***Proved developed reserves* —** In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

***Proved reserves* —** Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

***Proved undeveloped reserves* —** In general, proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

***PV-10* —** The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) non-property related expenses such as general and administrative expenses, derivatives, debt service and future income tax expense or (ii) depreciation depletion and amortization expense.

***SEC* —** The U.S. Securities and Exchange Commission.

***SEC pricing* —** The unweighted average first-day-of-the-month commodity price for crude oil or natural gas for each month within the 12-month period prior to the end of the reporting period, adjusted by lease for market differentials (quality, transportation, fees, energy content, and regional price differentials). The SEC provides a complete definition of prices in "Modernization of Oil and Gas Reporting" (Final Rule, Release Nos. 33-8995; 34-59192).

***Shelf* —** Water depths of up to 600 feet.

***Standardized Measure* —** The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the SEC and the Financial Accounting Standards Board (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

***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 gas regardless of whether such acreage contains proved reserves.

***Working interest* —** The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

***WTI or West Texas Intermediate* —** A light crude oil produced in the United States with an American Petroleum Institute gravity of approximately 38-40 and the sulfur content is approximately 0.3%.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Annual Report on Form 10-K (this "Annual Report") includes "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"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "will," "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "forecast," "may," "objective," "plan" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. Forward-looking statements may include statements about:

- business strategy;
- recoverable resources, reserves and prospective storage resources;
- drilling prospects, inventories, projects and programs;
- our ability to replace the reserves that we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program and other capital expenditures;
- realized oil and natural gas prices;
- risks related to the pending and future mergers and acquisitions, such as the acquisition of QuarterNorth Energy Inc. ("QuarterNorth," and such transaction, the "QuarterNorth Acquisition"), including the risk that we may fail to complete such transaction on the terms contemplated or at all, and/or to realize the expected benefits of any such transaction;
- timing and amount of future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- future drilling and low carbon solutions plans;
- availability of pipeline connections on economic terms;
- competition, government regulations and legislative and political developments;
- our ability to obtain permits and governmental approvals;
- pending legal, governmental or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our integration of acquisitions, including the QuarterNorth Acquisition, and future performance of the combined company;
- future leasehold or business acquisitions on desired terms;
- costs of developing properties;
- general economic conditions, including the impact of continued inflation and associated changes in monetary policy;
- political and economic conditions and events in foreign oil, natural gas and NGL producing countries and acts of terrorism or sabotage;
- credit markets;
- volatility in the political, legal and regulatory environments ahead of the upcoming domestic and foreign presidential elections;
- estimates of future income taxes;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- the success of our low carbon solutions business, including as a result of any development opportunities, permitting, access to capital to finance such opportunities, the timing and amount of revenues therefrom and potential future customers;

- the uncertainty inherent in estimating subsurface storage resources in our low carbon solutions projects;
- our ongoing strategy with respect to our Zama asset;
- uncertainty regarding our future operating results and our future revenues and expenses;
- impact of new accounting pronouncements on earnings in future periods; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility; global demand for oil and natural gas; the ability or willingness of OPEC and other state-controlled oil companies ("OPEC Plus") to set and maintain oil production levels and the impact of any such actions; the lack of a resolution to the war in Ukraine and increasing hostilities in the Middle East, and their impact on commodity markets; the impact of any pandemic and governmental measures related thereto; lack of transportation and storage capacity as a result of oversupply, government and regulations; the effect of a possible U.S. government shutdown and resulting impact on economic conditions and delays in regulatory and permitting approvals; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes, winter storms and loop currents; cybersecurity threats; sustained inflation and the impact of central bank policy in response thereto; environmental risks; failure to find, acquire or gain access to other discoveries and prospects or to successfully develop and produce from our current discoveries and prospects; geologic risk; drilling and other operating risks; well control risk; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production; cash flow and access to capital; the timing of development expenditures; potential adverse reactions or competitive responses to our acquisitions and other transactions; the possibility that the anticipated benefits of our acquisitions are not realized when expected or at all, including as a result of the impact of, or problems arising from, the integration of acquired assets and operations, risks associated with permitting for—and access to capital to finance—our CCS opportunities; and the other risks discussed in Part I, Item 1A. Risk Factors which are included herein.

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

Should one or more of the risks or uncertainties described herein occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

## SUMMARY RISK FACTORS

***Risks Related to our Business and the Oil and Natural Gas Industry***

- Oil and natural gas prices are volatile. Stagnation or declines in commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and available borrowings under our Bank Credit Facility and our ability to grow.
- Future exploration and drilling results are uncertain and involve substantial costs.
- Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic region, making us vulnerable to risks associated with operating in one geographic area.
- Production periods or relatively short reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.
- Our actual recovery of reserves may substantially differ from our proved reserve estimates.
- Our acreage must be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.
- The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.
- Inflationary issues and associated changes in monetary policy may result in increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.
- We may be unable to pursue our CCS business, either wholly or in significant measure, which could have a material adverse effect on our business, results of operations and financial condition.
- Our inability to benefit from Section 45Q tax credits could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition.
- We may be unable to provide the financial assurances in the amounts and under the time periods required by BOEM if it submits future demands to cover our decommissioning obligations. If in the future BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our associated federal offshore leases.
- Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.
- Global geopolitical tensions may create heightened volatility in oil, gas and NGL prices and could adversely affect our business, financial condition and results of operations.
- We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.
- Hedging transactions may limit our potential gains.
- Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine life and endangered and threatened species.
- Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.
- Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.
- If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.
- We may experience significant shut-ins and losses of production due to the effects of events outside of our control, including tropical storms and hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico and epidemics, outbreaks or other public health events.

- We are upgrading our accounting system to a more recent version and, if this upgraded version proves ineffective or we experience difficulties with the migration, we may be unable to timely or accurately prepare financial reports.

***Risks Related to our Capital Structure and Ownership of our Common Stock***

- Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility, and the indentures governing our New Senior Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.
- A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.
- We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.
- We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.
- Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our current and future financial position and results of operations.
- We may not realize the anticipated benefits from our current and future acquisitions, and we may be unable to successfully integrate future acquisitions.
- Our current and future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.
- Resolution of litigation could materially affect our financial position and results of operations.
- The interests of the Slim Family and its affiliates may differ from the interests of our other stockholders.

***Risks Related to the QuarterNorth Acquisition and our Integration of QuarterNorth Into our Business***

- We may not consummate the QuarterNorth Acquisition on the terms currently contemplated or at all.
- The failure to successfully integrate our business and operations with QuarterNorth in the expected time frame may adversely affect our future results.

## PART I

## Items 1 and 2. Business and Properties

### Overview

As used in this Annual Report and unless otherwise indicated or the context otherwise requires, references to "we," "us," "our," "Talos Energy Inc.," "Talos" and the "Company" refer to Talos Energy Inc. and its consolidated subsidiaries.

We are a publicly traded Delaware corporation and our common stock is listed on the New York Stock Exchange under the symbol "TALO."

We are a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through our operations, currently in the United States ("U.S.") and offshore Mexico both through oil and gas exploration and production ("Upstream") and the development of low carbon solutions opportunities. We leverage decades of technical and offshore operational expertise in the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. We are also utilizing our expertise to develop CCS projects to help reduce industrial emissions along the coast of the U.S. Gulf of Mexico ("Gulf Coast").

We combine our technical experience in geology, geophysics and engineering with innovative resource evaluation techniques and seismic imaging expertise to discover new resources. We rely on our operational experience to optimize our assets' production and reserve recovery, safely and responsibly. Finally, we leverage our commercial and corporate management experience to most effectively allocate our capital to balance risk and reward, grow our business and maximize long-term stockholder value.

### Business Strategy

We intend to increase stockholder value by growing our Upstream reserves, production, cash flow and future growth opportunities in a capital efficient manner while also exploring CCS opportunities. Our deep technical expertise and extensive physical operating experience also allows us to successfully manage our Upstream business and consistently make attractive acquisitions. We believe these same core competencies can be utilized to develop large-scale decarbonization projects to reduce industrial emissions.

#### *Upstream Strategy*

We maintain a large and diverse in-house technical staff focused on geology, geophysics, engineering and other technical disciplines, providing many decades of exploration and production experience in the key resource trends in which we focus. Our significant library of seismic data resources, which focuses on the U.S. Gulf of Mexico and offshore Mexico, allows our technical team to apply proprietary seismic reprocessing techniques to evaluate or re-evaluate potential resources across our asset portfolio. We also maintain deep in-house experience across our offshore operations, production operations, safety, facilities and business development teams.

Our strategic business development activities allow us to consistently identify and evaluate new opportunities through a wide range of potential avenues, including government lease sales, joint ventures and acquisitions, among others. Our proven track record of success through organic drilling opportunities frequently attracts potential drilling partners in projects that we operate, while in non-operated projects we leverage our core competencies to independently identify the best investment opportunities, review partner-proposed projects and be a value-added contributor. Our asset acquisition strategy is primarily focused on assets with a geological setting that can benefit from our ability to use our seismic database and technical expertise to re-evaluate and improve the acquired properties. Specifically, our acquisition focus areas target a variety of potential situations and sellers that are currently available in offshore basins, including single asset acquisitions, consolidation of private companies and broader asset package transactions. We seek to actively participate in government lease sales to identify and acquire attractive leasehold acreage, which in many cases has not been evaluated with the latest reprocessed seismic data, resulting in an opportunity for us to identify previously unknown drilling prospects.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple geologic trends, comprehensive geologic and geophysical seismic databases, extensive infrastructure and an attractive asset acquisition market. Our asset footprint, which includes operational control of several key shallow and Deepwater facilities, allows us to invest in a diverse set of opportunities ranging from in-field development to high impact exploration projects while optimizing our facilities to lower incremental operating costs structures. We also believe our operated infrastructure can be attractive to other operators looking for a host facility for their subsea tie-back projects, which allows us either to be involved in new investment opportunities or to offset the operating cost of these facilities.

Utilizing our core competencies in conjunction with a robust and active business development effort allows us to use the following strategies to increase stockholder value:

- ***Continuously Optimizing our Existing Asset Base —*** We benefit from our proven ability to enhance and extend the life of existing projects within our portfolio. Investments in optimization projects across our asset base aim to stabilize and improve the profile of producing assets by increasing recovery, production and cash flow with typically relatively low investment capital and risk. These projects allow for subsequent investment opportunities in exploitation and exploration projects.
- ***Conducting Development and Near-Field Projects In and Around Our Existing Asset Footprint —*** We undertake asset development and exploitation drilling projects in close proximity to our existing assets as well as facilities that we either own or have access to. These projects leverage ongoing operations and existing technical knowledge of the area, often coupled with recent proprietary seismic reprocessing evaluations to provide attractive incremental investment opportunities to grow reserves, production and cash flow in well-understood areas.
- ***Engaging in Exploration Activities to Grow our Asset Base and Potentially Unlock Significant New Resources —*** We conduct exploration drilling activities across our acreage set with risk-weighted investments that could establish significant new reserves and production. These projects are intended to optimize risk and reward across our portfolio of prospective drilling opportunities by finding and developing previously undiscovered resources along existing or emerging geological trends with the most efficient deployment of capital. When successful, exploration drilling activities can organically generate material new assets for the Company.
- ***Utilizing Acquisitions and Other Business Development Activities to Expand our Asset Base, Opportunity Set and Value Creation Potential —*** We rely on our commercial and business development activities to expand our asset base through the acquisition or optimization of additional or existing properties, respectively. Commercial and business development provides a key avenue to create additional value from the acquisition of undervalued properties where we can apply our technical and operational competencies to generate upside. Additionally, we utilize business development to acquire new leaseholds, enter new projects and increase or decrease working interests in various existing projects to optimize capital planning and our targeted risk/return profile for varying business conditions. Acquisition opportunities in our basin and, more broadly, in the offshore exploration and production segment in other basins around the world, are numerous and span a wide range of lifecycle stages, sizes and geographic variables. We expect to continue utilizing acquisitions and business development to grow our business in a manner that preserves a strong and healthy credit profile as well as a diverse and high-quality asset base.
- ***Maintaining Safety, Sustainability and Corporate Responsibility as Key Principles for Operations Across All Areas of our Business —*** We are focused on maintaining high standards of safety, environmental responsibility and corporate citizenship across all elements of our business. We closely monitor safety performance and consistently take steps to improve our performance. We strive to execute our business plan while simultaneously minimizing our environmental footprint, including emissions, potential spills and other impacts. Production from the Gulf of Mexico continues to provide some of the lowest greenhouse gas (“GHG”) emissions intensity due to the nature of subsea wells and established offshore pipeline and we continue to strive to lower our GHG emissions. Finally, we aim to be a good corporate citizen in the regions and communities where we operate.

### *Low Carbon Solutions Strategy*

Our CCS business is operated through our Talos Low Carbon Solutions (“TLCS”) subsidiary. TLCS intends to leverage its experience and technical expertise along the Gulf Coast, including subsurface engineering expertise, seismic interpretation capabilities, operations experience along the Gulf Coast and a solid track record of safety and environmentally responsible operations. The Gulf Coast is a critical industrial region with a large emissions footprint, while the underlying conventional geology in the area is believed to be ideal for carbon sequestration. TLCS intends to provide decarbonization solutions to assist industrial partners with carbon emissions capture, transportation and injection into sequestration sites in the region.

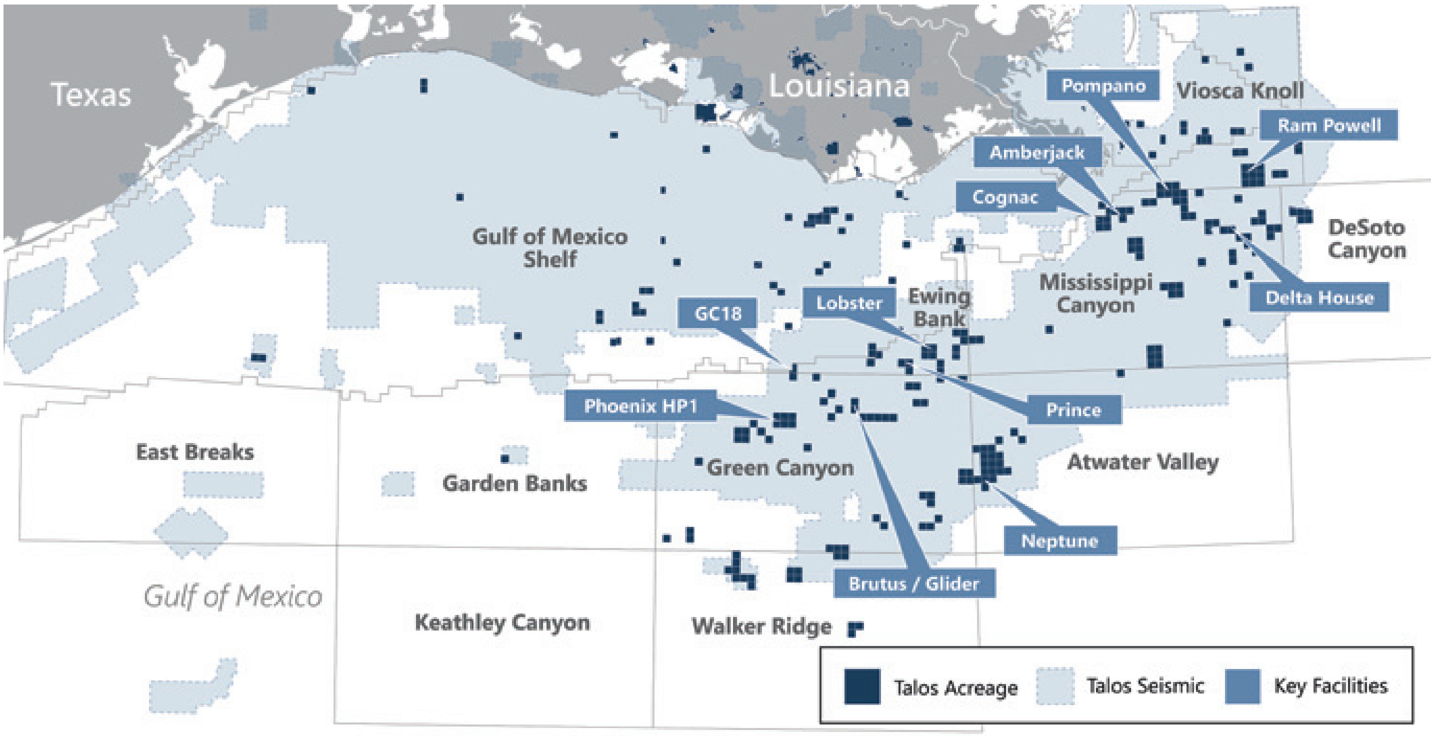
## Upstream Properties

### *United States Gulf of Mexico*

Our area of focus in the United States is the Gulf of Mexico Deepwater. Our strategy is concentrated in areas characterized by clearly defined infrastructure, well-known production history and geological well control, which reduces operational and investment risk.

We believe our Deepwater operations in the U.S. Gulf of Mexico provide significant potential growth opportunities through our drilling program. Through our technical approach of starting with known hydrocarbon systems and applying modern seismic reprocessing techniques, we have generated a substantial inventory of Deepwater prospects that we believe are capable of delivering production growth. We primarily focus our exploitation and exploration efforts around our existing infrastructure. This subsea tie-back strategy allows for better project economics and shorter periods between discovery and production as compared to design, construction and installation of a new facility following a discovery.

As of December 31, 2023, our core areas in the United States are summarized in the illustration below:




The following table sets forth a summary of certain key 2023 information regarding our core areas in the United States:

| | Estimated Proved Reserves | | | | | | |
|---|---|---|---|---|---|---|---|
| | MBoe | % Oil | % Natural Gas | % NGLs | % Proved Developed | Net Production (MBoe) | % Operated |
| Green Canyon | 41,342 | 75 % | 17 % | 8 % | 82 % | 7,807 | 88 % |
| Mississippi Canyon | 87,183 | 77 % | 15 % | 8 % | 91 % | 11,608 | 71 % |
| Shelf & Gulf Coast | 24,241 | 51 % | 42 % | 7 % | 75 % | 4,780 | 60 % |
| Total United States | 152,766 | 73 % | 20 % | 7 % | 86 % | 24,195 | 74 % |

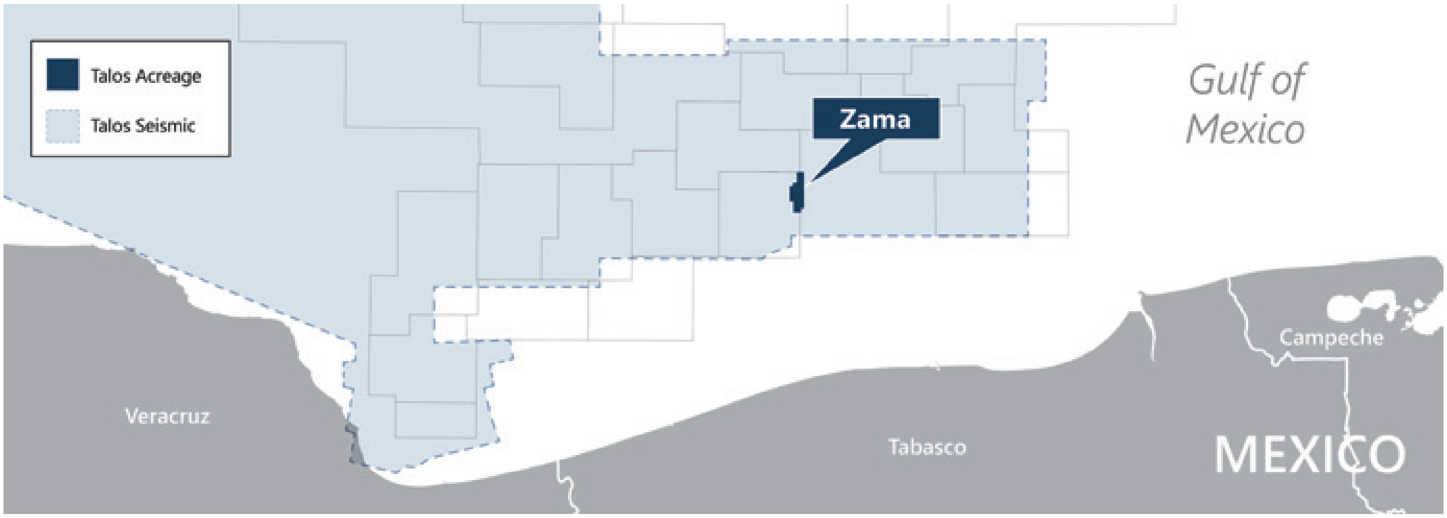
***Green Canyon*** — Green Canyon is a Deepwater region in the Central U.S. Gulf of Mexico and is a key focus area both industry-wide and for our exploration activities. We operate several production facilities in the region including Green Canyon 18, Lobster, Prince, Neptune, and Brutus/ Glider facilities. Additionally, we have a floating production unit, the Helix Producer I ("HP-I"), that is leased from Helix Energy Solutions Group, Inc. ("Helix").

***Mississippi Canyon*** — Mississippi Canyon is a Deepwater region in the eastern portion of the Central U.S. Gulf of Mexico with a track record of prolific production and ongoing exploration success that continues to unlock new resources. We operate several production facilities in the region including Pompano, Amberjack, Ram Powell, Cognac and our non-operated Delta House. We are active as both an operator and non-operating partner in numerous development projects and producing fields.

***Shelf and Gulf Coast*** — The U.S. Gulf of Mexico Shelf (the "Shelf") and Gulf Coast area spans an enormous geographical area across the basin and provides diverse production from numerous operated production facilities. The Shelf area is a producing region of the basin with attractive redevelopment and recovery enhancement opportunities.

***Mexico***

As of December 31, 2023, our area of focus in Mexico is the Block 7, Zama Unit Area segment located within the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Tabasco state. Such area is illustrated below:




***Block 7* —** On July 15, 2015, a Talos-led consortium was awarded Block 7 ("Block 7 Consortium") with a term of thirty years, starting in September 2015, and extendable for two additional five-year periods. The Company's participation interest in Block 7 is 35% and we are the operator. The Block 7 Consortium made a significant discovery in Block 7 after drilling the Zama-1 in 2017, less than two years after signing a production sharing contract ("PSC") for the block with Mexico's upstream oil and gas regulator, the National Hydrocarbon Commission ("CNH"). Subsequent to the Zama-1 discovery, we drilled three additional wells to further appraise the discovery.

Upon conclusion of the three well appraisal program, we determined that the Zama Field likely extended into a nearby offshore block owned by Petróleos Mexicanos ("PEMEX"). The Block 7 Consortium and PEMEX engaged a third-party reservoir engineering firm to evaluate initial tract participation within the Zama reservoir and concluded that the Block 7 Consortium holds 49.6% of the gross interest in the Zama Field and PEMEX holds 50.4%, which resulted in us holding a 17.35% interest in the unitized Zama Field. Mexico's Secretaría de Energía ("SENER") has designated PEMEX as the operator of the Zama unit.

The Zama Unit Development Plan was submitted by PEMEX to CNH for formal approval in March 2023 and was approved in June 2023. Modifications to the development plan were approved by CNH in February 2024 due to a revised timeline for infrastructure development activities. Additionally, an Integrated Project Team ("IPT") comprised of individuals from all four Zama Unit Holders has been established to manage the development and operation of Zama going forward. The IPT is designed to provide technical, operational and execution expertise, leveraging the talents from each of the Zama Unit Holders. The IPT will report to the Zama Unit Operating Committee, which includes representatives from each of the companies. We will co-lead the planning, drilling, construction, and completion of all Zama wells and co-lead the planning, execution, and delivery of Zama's offshore infrastructure. Additionally, we will co-lead the project management office.

On September 27, 2023, we sold a 49.9% interest in Talos Energy Mexico 7, S. de R.L. de C.V. ("Talos Mexico"), a wholly owned subsidiary of the Company to Zamajal, S.A. de C.V., a wholly owned subsidiary of Grupo Carso. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* and Note 7 — *Equity Method Investments* for additional information.

**Carbon Capture & Sequestration**

TLCS is leveraging decades of experience with conventional geology and Gulf Coast operations to pursue the development of future CCS projects. Project opportunities are actively being evaluated along the Gulf Coast. TLCS intends to identify, lease, mature and operate future CCS project opportunities and the associated sequestration sites. Areas of development are illustrated below as of December 31, 2023:


***Bayou Bend CCS —*** On March 11, 2022, Bayou Bend CCS LLC ("Bayou Bend") executed definitive lease documentation with the Texas General Land Office, formalizing the Jefferson County carbon sequestration site located in state waters offshore Jefferson County, Texas, near the Beaumont and Port Arthur, Texas industrial corridor. Chevron U.S.A Inc. ("Chevron"), which owns a 50% membership interest in Bayou Bend, became the operator effective March 1, 2023. During March 2023, Bayou Bend expanded its storage footprint through the acquisition of onshore acreage in Chambers and Jefferson Counties, Texas located within the Houston Ship Channel, Beaumont and Port Arthur regions. Equinor ASA acquired a 25% membership interest in August 2023. As of December 31, 2023, we own a 25% membership interest in Bayou Bend. For additional information on Bayou Bend, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments*.

***Harvest Bend CCS (formerly River Bend CCS) —*** In February 2022, Harvest Bend CCS LLC ("Harvest Bend") executed two agreements to lease acreage along the Mississippi River industrial corridor for a future CCS project. The agreements, which contained right of first refusal provisions on additional acreage, will allow for sequestration sites near existing pipeline infrastructure that may be used for the project. A separate right of first refusal agreement on incremental acreage was also executed in September 2023. In October 2023, Harvest Bend executed an additional agreement to lease acreage along the Mississippi River industrial corridor and two EPA Class VI permits were filed. In November 2023, seven additional agreements were conveyed to Harvest Bend from another wholly owned TLCS subsidiary that had nearby acreage. In December 2023, Harvest Bend became a multi-member limited liability company and entered into an operating agreement with a TLCS subsidiary to be operator. As of December 31, 2023, we own a 65% membership interest in Harvest Bend and an affiliate of Storegga Limited owns the remaining equity interest. For additional information on Harvest Bend, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments*.

***Coastal Bend CCS —*** Pursuant to an option agreement with the Port of Corpus Christi Authority ("PCCA") executed in February 2022, TLCS and Howard Energy Partners ("HEP") began pursuing commercial CCS opportunities on-site at the PCCA. On March 17, 2023, Coastal Bend CCS LLC ("Coastal Bend") became a multi-member limited liability company. As of December 31, 2023, we own a 50% membership interest in Coastal Bend. For additional information on Coastal Bend, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments*.

**Summary of Reserves**

The following table summarizes our estimated proved reserves which are all located in the United States:

| | Oil (MBbls) | Natural Gas (MMcf) | NGL (MBbls) | MBoe | Standardized Measure (in thousands) | PV -10 (in thousands) |
|---|---|---|---|---|---|---|
| ***Consolidated Entities:*** | | | | | | |
| **December 31, 2023** | | | | | | |
| Proved developed producing | 75,132 | 90,279 | 6,440 | 96,619 | | $ 2,911,256 |
| Proved developed non-producing | 23,093 | 51,544 | 3,517 | 35,200 | | 388,794 |
| Total proved developed | 98,225 | 141,823 | 9,957 | 131,819 | | 3,300,050 |
| Proved undeveloped | 12,590 | 38,048 | 2,016 | 20,947 | | 198,768 |
| Total proved | 110,815 | 179,871 | 11,973 | 152,766 | $ 3,043,488 | $ 3,498,818 |
| **December 31, 2022** | | | | | | |
| Proved developed producing | 63,049 | 103,245 | 6,194 | 86,451 | | $ 3,935,208 |
| Proved developed non-producing | 17,236 | 58,482 | 3,121 | 30,104 | | 661,882 |
| Total proved developed | 80,285 | 161,727 | 9,315 | 116,555 | | 4,597,090 |
| Proved undeveloped | 10,774 | 57,824 | 3,613 | 24,024 | | 584,009 |
| Total proved | 91,059 | 219,551 | 12,928 | 140,579 | $ 4,368,448 | $ 5,181,099 |
| **December 31, 2021** | | | | | | |
| Proved developed producing | 70,183 | 108,238 | 7,426 | 95,649 | | $ 3,073,168 |
| Proved developed non-producing | 23,237 | 78,204 | 4,366 | 40,637 | | 599,010 |
| Total proved developed | 93,420 | 186,442 | 11,792 | 136,286 | | 3,672,178 |
| Proved undeveloped | 14,344 | 49,911 | 2,643 | 25,306 | | 253,819 |
| Total proved | 107,764 | 236,353 | 14,435 | 161,592 | $ 3,440,611 | $ 3,925,997 |

***Reconciliation of Standardized Measure to PV-10***

PV-10 is a non-GAAP financial measure and differs from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies without regard to the specific tax characteristics of such entities. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 of our proved reserves (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| Standardized measure | $ 3,043,488 | $ 4,368,448 | $ 3,440,611 |
| Present value of future income taxes discounted at 10% | 455,330 | 812,651 | 485,386 |
| PV-10 (Non-GAAP) | $ 3,498,818 | $ 5,181,099 | $ 3,925,997 |

***Changes in Proved Developed Reserves***

The following table discloses our estimated changes in proved developed reserves:

| | Oil, Natural Gas and NGLs |
|---|---|
| | (MBoe) |
| ***Consolidated Entities:*** | |
| Proved developed reserves at December 31, 2022 | 116,555 |
| Changes during the year: | |
| Production | (24,195) |
| Revisions of previous estimates | (14,251) |
| Additions | 1,322 |
| Acquired | 42,684 |
| Conversion to proved developed | 9,704 |
| Total proved developed reserves changes | 15,264 |
| Proved developed reserves at December 31, 2023 | 131,819 |

Our proved developed reserves at December 31, 2023 increased by 15.3 MMBoe, or 13% primarily due to:

***Revisions of Previous Estimates —*** There was a decrease of 14.3 MMBoe from revisions of previous estimates. The revisions were primarily due to a 9.2 MMBoe decrease in reserve volumes due to the decrease in SEC Pricing of $17.47 per Bbl of oil and $4.05 per Mcf of natural gas and an additional decrease in the Phoenix field located in the Green Canyon core area due to well performance.

***Acquired —*** Acquired proved developed reserves of 42.7 MMBoe are attributable to the acquisition of EnVen Energy Corporation ("EnVen," and such acquisition, the "EnVen Acquisition") located primarily in the Green Canyon and Mississippi Canyon core areas. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***Development of Proved Undeveloped Reserves***

The following table discloses our estimated proved undeveloped ("PUD") reserve activities:

| | Oil, Natural Gas and NGLs | Future Development Costs |
|---|---|---|
| | (MBoe) | (in thousands) |
| ***Consolidated Entities:*** | | |
| Proved undeveloped reserves at December 31, 2022 | 24,024 | $ 478,511 |
| Changes during the year: | | |
| Extensions and discoveries | 4,040 | 29,624 |
| Revisions of previous estimates | (3,831) | (176,869) |
| Acquired | 6,418 | 141,651 |
| Conversion to proved developed | (9,704) | (188,161) |
| Total proved undeveloped reserves changes | (3,077) | (193,755) |
| Proved undeveloped reserves at December 31, 2023 | 20,947 | $ 284,756 |

Our PUD reserves at December 31, 2023 decreased by 3.1 MMBoe, or 13% primarily due to:

***Extensions and Discoveries —*** Extensions and discoveries of 4.0 MMBoe are primarily attributable to the Brutus Field located in the Green Canyon core area.

***Revisions of Previous Estimates —*** Downward revisions of 3.8 MMBoe are primarily due to a decrease of 3.2 MMBoe from the removal of a natural gas weighted opportunity in the Mississippi Canyon core area as a result of the change in the natural gas commodity environment.

***Acquired —*** Acquired proved undeveloped reserves of 6.4 MMBoe are attributable to the EnVen Acquisition located primarily in the Green Canyon and Mississippi Canyon core areas. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***Conversion to Proved Developed —*** Conversions of 9.7 MMBoe are attributable to successful drilling of our wells Venice and Lime Rock, which tie back to our Ram Powell facility as well as our MC 28 Mt. Hunter well in the Pompano Field, which are all located in the Mississippi core area.

We annually review all PUD reserves to ensure an appropriate plan for development exists. Our PUD reserves are required to be converted to proved developed reserves within five years of the date they are first booked as PUD reserves, unless the reserves are associated with an existing producing zone. Future development costs associated with our PUD reserves at December 31, 2023 totaled approximately $284.8 million, of which $131.0 million, $77.5 million and $76.2 million is attributable to our Mississippi Canyon, Green Canyon and Shelf and Gulf Coast core areas, respectively. When considering capital expenditures associated with other exploration projects and abandonment obligations, we expect to fund the development of PUD reserves using cash flows from operations and, if needed, availability under the Company's senior reserve-based revolving credit facility (the "Bank Credit Facility"), in each future annual period prior to the five year expiration. Our 2024 drilling program includes development of PUD reserves, and the conversion rate may not be uniform due to obligatory wells, newly acquired PUD reserves and production performance targets.

**Internal Controls over Reserve Estimates and Reserve Estimation Procedures**

At December 31, 2023, 2022 and 2021, proved oil, natural gas and NGL reserves attributable to our net interests in oil and natural gas properties were estimated and compiled for reporting purposes by our reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists, as described in further detail below.

Our policies regarding internal controls over the determination of reserves estimates require reserves quantities, reserves categorization, future producing rates, future net revenue and the present value of such future net revenue prepared using the definitions set forth in Regulation S-X, Rule 4-10(a) and subsequent SEC staff interpretations and guidance. These internal controls, which are intended to ensure reliability of our reserves estimations, include, but are not limited to, the following:

- reserve information, as well as models used to estimate such reserves, is stored on secure database applications to which only authorized personnel are given access rights consistent with their assigned job function;
- a comparison of historical expenses is made to the lease operating costs in the reserve database;
- internal reserves estimates are reviewed by well and by area by our reservoir engineers. A variance analysis by well to the previous year-end reserve report is performed;
- reserve estimates are reviewed and approved by certain members of senior management, including our President and Chief Executive Officer;
- our management requires that the independent petroleum engineers and geologists and our reserve quantities and calculation of the net present value of the reserves, collectively, vary by no more than 10% in the aggregate, in accordance with Society of Petroleum Evaluation Engineers ("SPEE") auditing standards;
- data is transferred to NSAI through a secure file transfer protocol site; and
- material reserve variances are discussed among NSAI, as applicable, our internal reservoir engineers and our Director of Reserves to ensure the best estimate of remaining reserves.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil, natural gas and NGLs that are ultimately recovered.

During the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil, natural gas and NGL production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. When compared on a well by well basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. NSAI determined that its estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued unqualified audit opinions on our reserves as of December 31, 2023, 2022 and 2021 based upon its evaluations. NSAI concluded that our estimates of reserves were, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPEE. The 2023 NSAI report is filed as Exhibit 99.1 to this Annual Report.

### Technologies Used in Reserve Estimation

The SEC's reserves rules allow the use of techniques that have been proved 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reservoir engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, development costs and workovers, all of which may vary considerably from actual results;
- future prices of oil, natural gas and NGLs, which may vary considerably from those mandated by the SEC; and
- the judgment of the persons preparing the estimates.

### Qualifications of Primary Internal Engineer

Our Director of Reserves is the technical person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating reserve audits conducted by NSAI. He has over 48 years of industry experience with positions of increasing responsibility, including 40 years as a reserves evaluator or manager. His further professional qualifications include a State of Texas Professional Engineering License, extensive internal and external reserve training and asset evaluation. In addition, he is an active participant in industry reserve seminars and professional industry groups, and has been a member of the Society of Petroleum Engineers for over 48 years. He reports directly to our Vice President of Corporate Development.

### Drilling Activity

The following table sets forth our drilling activity:

| | Exploratory and Appraisal Wells | | | | | | Development Wells | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Productive[(1)] | | Dry[(2)] | | Total | | Productive[(1)] | | Dry[(2)] | | Total | | Total | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| ***Consolidated Entities:*** | | | | | | | | | | | | | | |
| **Year Ended December 31, 2023** | | | | | | | | | | | | | | |
| United States | 3.0 | 1.3 | 5.0 | 2.1 | 8.0 | 3.4 | 7.0 | 3.0 | — | — | 7.0 | 3.0 | 15.0 | 6.4 |
| Mexico | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Total | 3.0 | 1.3 | 5.0 | 2.1 | 8.0 | 3.4 | 7.0 | 3.0 | — | — | 7.0 | 3.0 | 15.0 | 6.4 |
| **Year Ended December 31, 2022** | | | | | | | | | | | | | | |
| United States | — | — | 1.0 | 1.0 | 1.0 | 1.0 | 6.0 | 2.8 | — | — | 6.0 | 2.8 | 7.0 | 3.8 |
| Mexico | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Total | — | — | 1.0 | 1.0 | 1.0 | 1.0 | 6.0 | 2.8 | — | — | 6.0 | 2.8 | 7.0 | 3.8 |
| **Year Ended December 31, 2021** | | | | | | | | | | | | | | |
| United States | — | — | 2.0 | 1.5 | 2.0 | 1.5 | 5.0 | 2.4 | — | — | 5.0 | 2.4 | 7.0 | 3.9 |
| Mexico | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Total | — | — | 2.0 | 1.5 | 2.0 | 1.5 | 5.0 | 2.4 | — | — | 5.0 | 2.4 | 7.0 | 3.9 |
| ***Equity Method Investees:*** | | | | | | | | | | | | | | |
| **Year Ended December 31, 2023** | | | | | | | | | | | | | | |
| Mexico | — | — | — | — | — | — | — | — | — | — | — | — | — | — |

(1) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(2) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be productive, as opposed to the year the well was drilled.

As of December 31, 2023, we had wells actively drilling or completing and wells suspended or awaiting completion, as follows:

| | Actively Drilling or Completing | | | | Wells Suspended or Waiting on Completion | | | |
|---|---|---|---|---|---|---|---|---|
| | Exploratory | | Development | | Exploratory | | Development | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| ***Consolidated Entities:*** | | | | | | | | |
| United States | — | — | — | — | 1.0 | 0.5 | 1.0 | 0.1 |
| ***Equity Method Investees:*** | | | | | | | | |
| Mexico | — | — | — | — | 4.0 | 0.4 | — | — |

**Productive Wells**

The number of our productive wells is as follows for the year ended December 31, 2023:

| | Gross | Net |
|---|---|---|
| ***Consolidated Entities:*** | | |
| Crude oil | 259.0 | 191.3 |
| Natural gas | 76.0 | 37.7 |
| Total[1] | 335.0 | 229.0 |

(1) Includes 8.0 gross and 7.1 net wells with dual completions.

**Acreage**

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2023:

| | Developed Acres | | Undeveloped Acres | | Total Acres | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| ***Consolidated Entities:*** | | | | | | |
| United States: | | | | | | |
| Deepwater | 362,000 | 186,247 | 592,712 | 368,238 | 954,712 | 554,485 |
| Shelf | 261,929 | 175,775 | 53,572 | 33,088 | 315,501 | 208,863 |
| Total United States | 623,929 | 362,022 | 646,284 | 401,326 | 1,270,213 | 763,348 |
| ***Equity Method Investees:*** | | | | | | |
| Mexico[1] | — | — | 3,261 | 572 | 3,261 | 572 |

(1) Gross acreage for Mexico represents the gross acreage in Block 7, which Talos Mexico has a 35% participation interest. We hold a 50.1% equity interest in Talos Mexico. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments* for additional information.

Undeveloped acreage is considered to be leased acres 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 or not such acreage contains proved reserves. Included within undeveloped acreage are leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well holding such lease. The terms of our leases on undeveloped acreage as of December 31, 2023 are scheduled to expire as shown in the table below (the terms of which may be extended by drilling and production operations):

| | Consolidated Entities | | Equity Method Investees | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| 2024 | 94,043 | 45,873 | — | — |
| 2025 | 85,046 | 60,921 | — | — |
| 2026 | 74,880 | 58,473 | — | — |
| 2027 | 92,160 | 44,086 | — | — |
| 2028 | 17,280 | 4,367 | — | — |
| 2029 and beyond | 282,875 | 187,606 | 3,261 | 572 |
| Total | 646,284 | 401,326 | 3,261 | 572 |

### Crude Oil, Natural Gas and NGL Production, Prices and Production Costs

Our production volumes, average sales prices and average production costs are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| **Production Volumes:** | | | |
| Crude oil (MBbls) | 18,062 | 14,561 | 16,159 |
| Natural gas (MMcf) | 26,194 | 32,215 | 32,795 |
| NGLs (MBbls) | 1,767 | 1,793 | 1,875 |
| Total (MBoe) | 24,195 | 21,723 | 23,500 |
| Percent of MBoe from crude oil | 75 % | 67 % | 69 % |
| **Average Sales Price (including commodity derivatives):** | | | |
| Crude oil (per Bbl) | $ 73.59 | $ 68.40 | $ 49.67 |
| Natural gas (per Mcf) | $ 3.32 | $ 5.30 | $ 3.11 |
| NGLs (per Bbl) | $ 18.18 | $ 33.20 | $ 26.54 |
| Average (per Boe) | $ 59.86 | $ 56.46 | $ 40.61 |
| **Average Sales Price (excluding commodity derivatives):** | | | |
| Crude oil (per Bbl) | $ 75.17 | $ 93.75 | $ 65.86 |
| Natural gas (per Mcf) | $ 2.60 | $ 7.06 | $ 3.98 |
| NGLs (per Bbl) | $ 18.18 | $ 33.20 | $ 26.54 |
| Average (per Boe) | $ 60.26 | $ 76.05 | $ 52.96 |
| Average Lease Operating Expense (per Boe) | $ 16.10 | $ 14.18 | $ 12.07 |

### Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 16 — *Supplemental Oil and Gas Disclosures (Unaudited)*.

### Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalties, overriding royalties, and carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes and development obligations under oil and natural gas leases. As is customary in the industry in the case of undeveloped properties, often limited investigation of record title is made at the time of acquisition. Title search investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. To the extent title opinions or other investigations reflect defects affecting such undeveloped properties, we are typically responsible for curing any such title defects at our expense.

### Commodity Price Risks and Price Risk Management Activities

Production from our properties is marketed using methods that are consistent with industry practices. Sales prices for oil and natural gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. We enter into derivative contracts on our oil and natural gas production primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. For additional information regarding our commodity price risk and commodity derivative instruments, see Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

### Significant Customers

Oil and natural gas companies spend capital on exploration, drilling and production operations expenditures, the amount of which is generally dependent on the prevailing view of future oil and natural gas prices which are subject to many external factors which may contribute to significant volatility in future prices. We market the majority of our oil, natural gas and NGL production from the properties we operate and those we do not operate. Our customers consist primarily of major oil and gas companies, well-established oil and pipeline companies and independent oil and natural gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. For the year ended December 31, 2023, 54% and 21% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company and Valero Energy Corporation, respectively, which are the customers that individually represented 10% or more of our oil, natural gas and NGL revenues.

## Competitive Conditions

The oil and natural gas business is highly competitive in the exploration for and acquisition of reserves, the acquisition of oil and natural gas leases, equipment and personnel required to find and produce reserves and in the gathering and marketing of oil, natural gas and NGLs. We compete with large integrated oil and natural gas companies as well as independent exploration and production companies. Certain of our competitors may have significantly more financial or other resources available to them. In addition, certain of the larger integrated companies may be better able to respond to industry changes, including price fluctuation, oil and natural gas demand and governmental regulations.

However, we believe our high quality oil-weighted production base, proven expertise in utilizing seismic technology to identify, evaluate and develop exploitation and exploration opportunities, balanced mix of assets in the U.S. Gulf of Mexico deep and shallow waters and significant operating control give us a strong competitive position relative to many of our competitors.

## Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis. Generally, but not always, the demand for gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may impact general seasonal changes in demand.

## Insurance Matters

Our oil and natural gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrolled flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution or other risks, any of which could result in substantial losses to us. In addition, our oil and natural gas properties are located in the U.S. Gulf of Mexico, which makes us more vulnerable to tropical storms, loop currents and hurricanes. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flow. Although we obtain insurance against some of these risks, we cannot insure against all possible losses. As a result, any damage or loss not covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

We have insurance policies to cover some of our risk of loss associated with our operations, and we maintain the amount of insurance we believe is prudent. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and the cost of replacement facilities. Our general liability insurance program provides a limit of $500.0 million for each occurrence and in the aggregate, and includes varying deductibles. Our Oil Pollution Act insurance is subject to a maximum of up to $150.0 million for each occurrence and in the aggregate, including a $100,000 retention. Coverage is provided for damage to our assets resulting from a named U.S. Gulf of Mexico windstorm; however, such coverage is subject to a maximum of $250.0 million per named windstorm and in the aggregate, and is also subject to a maximum of $15.0 million per occurrence retention dependent on location. We separately maintain an operators extra expense policy with additional coverage for an amount up to $500.0 million for U.S. Gulf of Mexico Deepwater drilling wells, $150.0 million for U.S. Gulf of Mexico Shelf drilling wells, $75.0 million for U.S. Gulf of Mexico producing and shut-in wells, $75.0 million for drilling and workover in inland waters and $25.0 million for drilling and workover in onshore fields that would cover costs involved in making a well safe after a blow-out or getting the well under control; re-drilling a well to the depth reached prior to the well being out of control or blown out; costs for plugging and abandoning the well; and costs for clean-up and containment and for damages caused by contamination and pollution. For our Mexico insurance policies, we maintain $250.0 million in operators extra expense coverage for operations and $500.0 million per occurrence and aggregate limit for general liability.

We may increase or decrease insurance coverage around our key strategic assets, including potentially purchasing catastrophic bond instruments. A portion of our highest value assets, which are located in the Phoenix Field, produce through the HP-I floating production system, which has the capability to disconnect and move away in the event of a storm, mitigating the risk of property damage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel for liability related to work performed for us. Under these agreements, we generally are indemnified against third party claims related to the injury or death of our customers' or vendors' personnel, subject to the application of various states' laws.

**Government Regulation**

Exploration and development and the production and sale of oil, natural gas and NGLs are subject to extensive federal, state, local and foreign laws and regulations. An overview of these legal requirements is set forth below. Historically, our compliance with existing requirements has not had a material adverse effect on our financial position, results of operations or cash flows. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Because such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of compliance. Although the regulatory burden increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

***General Overview*** — Our oil and natural gas operations and CCS projects are subject to various federal, state, local and foreign laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and natural gas properties;
- drilling and casing of wells;
- issuance of permits in connection with exploration, drilling and production and CCS activities;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions permitting or limitations;
- protection of marine life and endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and natural gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- requirements for the posting of supplemental bonds or providing other forms of financial assurance for the plugging and abandonment of wells located in the U.S. Gulf of Mexico and offshore Mexico and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines in those areas ("P&A" or "decommissioning" obligations);
- performance of P&A obligations; and
- transportation of production.

***Outer Continental Shelf ("OCS") Regulation —*** Our operations on federal oil and natural gas leases in the U.S. Gulf of Mexico are subject to extensive regulation by BSEE, BOEM and the Office of Natural Resources Revenue ("ONRR") under the purview of the U.S. Department of the Interior ("DOI"). Federal leases are awarded by BOEM based on competitive bidding with relatively standardized lease terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Act ("OCSLA"). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency ("EPA"), lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, P&A of wells on the OCS, calculation of and valuation of production related to royalty payments, and decommissioning of facilities, structures and pipelines.

U.S. federal offshore oil and gas leasing and permitting practices have been subject to numerous challenges, delays, and moratoriums over the last three years which has curtailed our ability to seek additional new federal leases and may continue to delay or prevent us from bidding and obtaining new federal leases. Additionally, in response to a November 2021 report from the DOI on federal oil and gas leasing and permitting practices, the Inflation Reduction Act of 2022 (the "IRA 2022") increased onshore royalty rates to 16.7% and offshore royalty rates to no less than 16.7% but not more than 18.8% for the next ten years, thereby ensuring the full value of the leased tracts are captured. The extent to which the Biden Administration will act upon the DOI report's other recommendations cannot be predicted at this time, but any additional action may cause delay or prevent us from obtaining new federal leases.

In January 2023, BOEM released its final environmental impact statement for Lease Sales 259 and 261 and, in March 2023, announced the results of Lease Sale 259, in which we were the high bidder on four offshore blocks, and were awarded leases on all four blocks. BOEM held Lease Sale 261 on December 20, 2023, in which we were the high bidder on thirteen offshore blocks and were awarded four leases as of February 16, 2024. As BOEM is still in its bid evaluation process, we are awaiting BOEM's award decisions on our remaining high bids. Any reduction in the size or number of offshore blocks designated by BOEM for future leasing activities, as well as delays in BOEM awarding leases to operators either as a result of NEPA-related days or legal challenges to BOEM leasing decisions, has the potential to materially and adversely affect our business and results of operations.

Laws and regulations related to our business continually evolve and change depending on the political climate, but generally our business has experienced increased safety and environmental restrictions and permitting and performance requirements during our existence. Our operations are currently subject to rigorous standards relating to the design, operation and maintenance of blow-out preventers, real-time monitoring of Deepwater, high temperature, high pressure drilling activities, and enhanced reporting requirements.

The Biden Administration has taken a number of actions to adopt more stringent safety, permitting and performance requirements. For example, on August 23, 2023, BSEE published a final well control rule for drilling, workover, completion and decommissioning operations, revising the 2019 rule and increasing the requirements for blowout preventer systems ("BOPs") and other well control and operations requirements. The final rule requires, among other things, that BOPs are always able to close and seal the wellbore to the well's maximum anticipated surface pressure, failure analysis and investigations start within 90 days of an incident, failure data is reported to both a designated third party and BSEE, and independent third-party qualifications are submitted to BSEE with associated permit applications. Compliance with Biden Administration legislative, executive and regulatory actions or any other legal initiatives that impact oil and natural gas exploration, development and production activities on the OCS could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Our failure to comply with legal requirements under the OCSLA, our lease or applicable regulations may ultimately result in BOEM canceling one or more of our leases, which such cancellation could adversely affect our financial condition and operations.

Furthermore, tropical storms, loop current, hurricanes and other adverse weather conditions in the U.S. Gulf of Mexico can have a significant impact on oil and natural gas operations and can result in suspended operations and significant damage to key infrastructure and extensive pollution. In an effort to reduce the potential for future damage, BOEM and BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. More stringent, requirements could be proposed or finalized in the future, which could increase our operating costs and/or capital expenditures.

In addition, in order to cover the various decommissioning obligations of lessees on the OCS, BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS.

There has been substantial uncertainty with respect to BOEM's financial assurance requirements in recent years and BSEE's approach to predecessor liability for decommissioning obligations. In April 2023, BSEE published its Final Rule entitled, "Risk Management, Financial Assurance, and Loss Prevention – Decommissioning Activities and Obligations," wherein BSEE clarified decommissioning responsibilities for RUE grant holders and formalized BSEE's policies regarding performance by predecessors ordered to decommission OCS facilities. The final rule withdraws a rule proposed during the Trump Administration that sought to amend BSEE's regulations requiring the agency to proceed in reverse chronological order against predecessor lessees, owners of operating rights and grant holders when requiring such entities to perform their accrued decommissioning obligations upon failure to perform by current lessees, owners, or holders. Under the final rule, BSEE may issue an order to predecessors to perform accrued decommissioning obligations, including beginning maintenance and monitoring within thirty days, designating an operator for decommissioning within ninety days, and submitting a decommissioning plan within one hundred fifty days.

In addition, in June 2023, BOEM published a proposed rule that, if adopted as initially proposed, would substantially revise the supplemental financial assurance requirements applicable to offshore oil and gas operations. The proposed rule would change the current criteria used to determine whether OCS lease and grant holders are required to secure supplemental financial assurance. The proposed rule would no longer use the current 5-point test in determining whether an OCS lessee or grant holder is required to obtain supplemental financial assurance and instead proposes a simplified test: (1) the credit rating of the lessee and, where applicable, (2) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. Under the proposed rule, BOEM would no longer consider or rely upon the financial strength of predecessors in determining whether, or how much, supplemental financial assurance should be provided by current lessees and grant holders. BOEM would not require supplemental financial assurance above the base bond requirements in three cases: (1) where a lessee has an investment grade credit rating (i.e., a credit rating from a Nationally Recognized Statistical Ratings Organizations, or NRSRO, that is greater than or equal to either BBB- from S&P or Baa3 from Moody's, or its equivalent, or a proxy credit rating greater than or equal to either BBB- or Baa3, as determined by the Regional Director and based upon a company's audited financial information with an accompanying auditor's certificate); (2) where there are multiple co-lessees on a lease and any one of those lessees meets the credit rating threshold; and (3) for any lease on which all lessees are rated below investment grade, where the value of the lease's proved oil and gas reserves is at least three times that of the estimated decommissioning cost estimate. BOEM proposes to phase in compliance with the new requirements over a three-year period. The extended public comment period closed on September 7, 2023, and BOEM is reviewing the comments received. At this time, we cannot predict whether BOEM will adopt the final rule in its current form or at all, the timing for any final decision, or whether any changes will result from the public notice and comment process, but will continue to monitor this rulemaking. According to the Fall 2023 Unified Agenda, the final rule is expected in the second quarter of 2024.

Separately, in August 2021, BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder in respect of any new, more stringent, NTLs or final rules on supplemental bonding published by BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

***Regulation in Shallow Waters Off the Coast of Mexico —*** Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by SENER, the CNH and other Mexican regulatory bodies. The CNH is responsible for, among other things, overseeing the tender procedures for awarding contracts for the exploration and production of oil and natural gas in Mexican waters, managing and supervising contracts that have been awarded, and approving exploration and production plans. The PSC that the Block 7 Consortium entered into for the development of this acreage contains terms that impose on us the duty to comply with various laws and regulations. These laws and regulations govern, among other things, the exploration and exploitation of hydrocarbons (including certain national content requirements), the treatment, conveyance, marketing, transport and storage of petroleum, and requirements for industrial safety, operational security, and facility decommissioning. Failure to comply can result in the imposition of monetary penalties, revocation of permits, rescission of the PSC, suspension of operations, and ordered decommissioning of offshore facilities and systems. The laws and regulations governing activities in the Mexican energy sector were significantly reformed in 2013, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore shallow waters.

***Hydrocarbon Export Regulation in Mexico —*** Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by SENER. Such regulations are subject to change, and it is possible that the Mexican National Agency of Industrial Safety and Environmental Protection of the Hydrocarbons Sector ("ASEA") or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. For example, in December 2020, SENER published regulations affecting the granting of permits for the import and export of hydrocarbons. These regulations imposed additional constraints on permit applicants, and granted SENER more discretion in issuing, modifying, and revoking those permits. Previously, such permits would have had a term of 20 years – the December 2020 regulations limit terms to 5 years, restrict extensions and add new requirements. Subsequently, in May 2021, the Mexican government amended its federal Hydrocarbons Law in a manner that is anticipated to be beneficial to PEMEX, but have an adverse impact on privately-held oil and gas energy companies including by way of example, (i) authorizing SENER and the Mexican Energy Regulatory Commission (the "CRE") to suspend or revoke hydrocarbon permits if there is imminent danger to national security, energy security or the national economy; (ii) allowing the government to temporarily occupy the facilities of hydrocarbon permit-holders to safeguard the national interest and hand over the operation of such facilities to State-owned entities, such as PEMEX; and (iii) allowing for denial by default of applications for new permits of private companies if the authorities do not respond within 90 days. Also in May 2021, the Mexican government made a second amendment to its Hydrocarbons Law, which such amendment halts the CRE's power to enforce asymmetric regulation in the hydrocarbon, petroleum products and petrochemical markets, which regulation obligates PEMEX to comply with certain obligations that effectively limits its market position relative to its competitors. Amparo actions are being pursued in local courts in response to these legal changes and, as interim measures, court actions suspended the December 2020 regulations in March 2021, partially suspended portions of the first amendment to the Hydrocarbons Law (such suspension including the authorization to temporarily occupy facilities of permit-holders) in May 2021 and suspended the second amendment to the Hydrocarbons Law in May 2021.

**Environmental and Occupational Safety and Health Regulations**

We are subject to various federal, state, local and foreign regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- various environmental permitting requirements, such as permits for wastewater discharges;
- the development of emergency response and spill contingency plans;
- specific operating criteria addressing worker protection; and
- protection of private and public surface and ground water supplies.

Based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and it is possible such expenses will continue to increase in the future. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters, and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, natural resource damages or the issuance of injunctive relief (including orders to cease operations). Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Additionally, President Biden has made climate change arising from GHG emissions a priority under his administration. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

We expect to continue making expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. Our insurance coverage provides for the reimbursement to us of certain costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure against pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses, and since regulatory requirements frequently change and may become more stringent under the Biden Administration including in respect of GHG emissions, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

***Water Discharges —*** Our discharges into waters of the United States are limited by the federal Clean Water Act, as amended ("CWA"), and analogous state laws. The CWA prohibits any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies. These discharge permits also include monitoring and reporting obligations. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. Violations of the CWA can result in suspension, debarment or the imposition of statutory disability, each of which prevents companies and individuals from participating in government contracts and receiving some non-procurement government benefits. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure plans.

***Oil Pollution Act —*** The Oil Pollution Act of 1990, as amended ("OPA"), holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States and for certain damages from such spills. OPA assigns joint and several strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA's damages liability cap is currently $167.8 million; however, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party failed to report a spill or cooperate fully in the clean-up. OPA also requires responsible parties to maintain evidence of financial responsibility in prescribed amounts. OPA currently requires a minimum financial responsibility demonstration of between $35 million to $150 million, based on a worst case oil spill discharge volume, for companies operating on the OCS, although BOEM may increase this amount in certain situations, but in no event greater than $150 million. From time to time, the United States Congress has proposed, but not adopted, amendments to OPA raising the financial responsibility requirements. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

***National Environmental Policy Act —*** The National Environmental Policy Act, as amended ("NEPA"), requires federal agencies, including the DOI, to consider the impacts their actions have on the human environment, and to prepare detailed statements for major federal actions having the potential to significantly impact the environment. These requirements can lead to additional costs and delays in permitting for operators as the DOI or its bureaus may need to prepare Environmental Assessments ("EA") and more detailed Environmental Impact Statements ("EIS") in support of its leasing and other activities that have the potential to significantly affect the quality of the environment. If the EA indicates that no significant impact is likely, then the agency can release a finding of no significant impact and carry on with the proposed action. Otherwise, the agency must then conduct a full-scale EIS. In July 2020, the Council on Environmental Quality ("CEQ") under former President Trump's Administration published a final rule modifying the NEPA including, among other things, establishing a time limit of two years for preparation of EIS statements and one year for the preparation of EAs, and also eliminating the responsibility to consider cumulative effects of a project. While the July 2020 rule modifying NEPA was subject to litigation in several federal district courts, the CEQ, under the Biden Administration, announced in October 2021, that it intended to make three significant changes to the 2020 final rule, including authorizing agencies to consider direct, indirect and cumulative effects of major federal actions including upstream and downstream GHG emissions impacts of fossil fuel projects, allowing agencies to determine the purpose and need of a project, which allows consideration of less-harmful alternatives, and affording agencies greater flexibility in crafting their own NEPA procedures, consistent with CEQ regulations, so as to meet the agencies' and public's needs.

To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes, a move considered as "Phase I" of the Biden Administration's two-phased approach to modifying the NEPA. On July 28, 2023, the CEQ announced a "Phase 2" Notice of Proposed Rulemaking, the "Bipartisan Permitting Reform Implementation Rule," which revises the implementing regulations of the procedural provisions of NEPA and implements the amendments to NEPA included in the June 3, 2023, Fiscal Responsibility Act of 2023. The public comment period for the proposed rule closed on September 29, 2023, and the final rule is expected in the second quarter of 2024. Additionally, in January 2023, the CEQ released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under NEPA. The CEQ's interim guidance, effective upon publication, encourages agencies to consider, among other things, effects from upstream and downstream GHG emissions of fossil fuel projects and, in many cases, use estimates of the social costs of GHG emissions when communicating those findings to the public. The NEPA process involves public input through comment. These comments, as well as the agency's analysis of the proposed project, can result in changes to the nature of a proposed project, such as by limiting the scope of the project or requiring resource-specific mitigation. The adequacy of the agency's NEPA process can be challenged in federal court by process participants. This process may result in delaying the permitting and development of projects, and result in increased costs.

***Endangered Species Act —*** The Endangered Species Act, as amended ("ESA"), restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the Migratory Bird Treaty Act, as amended ("MBTA"), implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit. The U.S. Fish and Wildlife Service ("FWS") under former President Trump issued a final rule on January 7, 2021, which notably clarifies that criminal liability under the MBTA will apply only to actions "directed at" migratory birds, its nests or its eggs; however, in October 2021, the FWS under the Biden Administration revoked the Trump Administration's rule on incidental take and published an advanced notice of proposed rulemaking to codify a general prohibition on incidental take while establishing a process to regulate or permit exceptions to such a prohibition. On February 9, 2023, the FWS published a proposed rule that revised the requirements for an incidental take permit application. A final rule is scheduled for release in the first quarter of 2024. The Marine Mammal Protection Act, as amended ("MMPA"), similarly prohibits the taking of marine mammals without authorization. Additionally, the FWS may make determinations on the listing of species as threatened or endangered under the ESA and litigation with respect to the listing or non-listing of certain species may result in more fulsome protections for non-protected or lesser-protected species. We conduct operations on oil and natural gas leases in areas where certain species that are protected by the ESA, MBTA and MMPA are known to exist and where other species that could potentially be protected under these statutes are known to exist. The FWS or the National Marine Fisheries Service ("NMFS") may designate critical habitat that it believes is necessary for survival of a threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for oil and natural gas development. For example, in April 2019, the NMFS listed the Rice's whale, determined to be a subspecies of the Bryde's whale, as endangered under the ESA. On July 24, 2023, NMFS proposed to designate approximately 28,270.65 square miles of the Gulf of Mexico as critical habitat for the Rice's whale. NMFS is currently reviewing comments and is expected to issue a final critical habitat designation for the Rice's whale in 2024. These statutes may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas. Consequently, the designation of new species or their critical habitat for protection under the ESA, MBTA, and MMPA could adversely affect our business and results of operations and increase our operating costs.

***Hazardous Substances and Waste Management —*** The Resource Conservation and Recovery Act, as amended ("RCRA"), generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in increased costs to manage and dispose of generated wastes. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

***Comprehensive Environmental Response, Compensation and Liability Act —*** The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible persons" may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Further, it is not uncommon for coastal landowners or other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

***Air Emissions*** — The Clean Air Act, as amended ("CAA"), and comparable state statutes restrict the emission of air pollutants and affect both onshore and offshore oil and natural gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed, and continues to develop, more stringent regulations governing emissions of toxic air pollutants and is considering the regulation of additional air pollutants and air pollutant parameters. For example, in 2015, the EPA under the Obama Administration issued a final rule under the CAA, making the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone more stringent. The EPA is currently reconsidering a prior decision to retain the 2015 ozone standard. Any revision to the NAAQS and state implementation of the same could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

***Worker Health and Safety*** — The Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

***Climate Change* —**The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States and in foreign countries. President Biden has made action on climate change a priority of his administration's agenda and laws such as the IRA 2022 advance numerous climate-related objectives. Additionally, numerous proposals have been made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHG as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the EPA has adopted regulations under the existing CAA that, among other things, impose pre-construction and operating permit requirements on certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources and implement New Source Performance Standards directing the reduction of methane from certain new, modified or reconstructed facilities in the oil and natural gas sector. Compliance with these rules or others could result in increased compliance costs on our operations.

On December 2, 2023, the EPA published its final rule establishing more stringent methane rules for new, modified, and reconstructed facilities, known as Quad Ob, as well as standards for existing sources for the first time ever, known as Quad Qc. Under the final rules, states have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges, so we are unable to predict at this time the scope of any final regulatory requirements and the expected cost to comply with such requirements. Any increase in regulatory scope and oversight may increase compliance expenditure or mitigation costs for our operations.

At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement among participating nations to limit their GHG emissions through individually-determined emissions reduction goals every five years after 2020. President Biden announced in April 2021 a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. Subsequent climate conferences have resulted in pledges by the United States and others to monitor, report and reduce methane emissions (including all feasible reductions for the energy sector) and calls for accelerated efforts toward the phase out of inefficient fossil fuel subsidies. Most recently, at the 28th Conference of the Parties ("COP28"), participants signed onto an agreement to transition "away from fossil fuels in energy systems in a just, orderly and equitable manner" and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set. The impacts of these orders, pledges and agreements, and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement and subsequent climate conferences or other international conventions cannot be predicted at this time and it is unclear what additional initiatives may be adopted or implemented that may have a negative impact on our financial condition.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risk regarding climate change. In the United States, President Biden has issued several executive orders calling for more expansive action to address climate change and limit new oil and gas operations on federal lands and waters. See Part I, Items 1 and 2. Business and Properties — Government Regulation — Outer Continental Shelf ("OCS") Regulation for more information. Other actions that could be pursued by the Biden Administration include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquified natural gas ("LNG") export facilities, as well as more stringent emissions standards for oil and gas facilities. For example, on January 26, 2024, President Biden announced a temporary pause on pending decisions on new exports of LNG to countries that the United States does not have free trade agreements with, pending Department of Energy review of the underlying analyses for authorizations. The pause is intended to provide time to integrate certain considerations, including potential energy cost increases for consumers and manufacturers and the latest assessment of the impact of GHG emissions, to ensure adequate safeguards against health risks are in place. Additionally, the IRA 2022 was signed into law in August 2022, and contains hundreds of billions of dollars in incentives for the development of renewable energy, clean fuels, electric vehicles and supporting infrastructure, and carbon capture and sequestration, among other provisions. These incentives could further accelerate the transition of the United States' economy away from the use of fossil fuels toward lower- or zero-carbon emissions alternatives. The IRA 2022 also imposes the first ever federal fee on the GHG emissions through a methane emissions charge. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. We are not currently a defendant in any of these lawsuits but 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.

Additionally, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in fossil fuel energy companies such as ours, but concerned about the potential effects of climate change, may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices that favor "clean" power sources, such as wind and solar, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. At COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding to fossil fuel energy companies.

In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector, and, in September 2022, announced that six of the U.S. largest banks will participate in a pilot climate scenario analysis exercise to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. The Federal Reserve released its pilot exercise in January 2023 which is designed to analyze the impact of both physical and transition risks related to climate change on specific assets of the banks' portfolios. In October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corporation (the "FDIC") released a finalized set of principles guiding financial institutions with $100 billion or more in assets on the management of physical and transition risks associated with climate change. While we cannot predict what additional developments may arise from these various activities, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations. Separately, the SEC released a proposed rule in March 2022 that would establish a framework for the reporting of climate risks, targets and metrics. A final rule is anticipated to be released in the second quarter of 2024. The SEC has also announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege that an issuer's existing climate disclosures are misleading, deceptive or deficient. Such agency action could also increase the potential for private litigation. Relatedly, California has enacted new laws requiring additional disclosure with respect to certain climate-related risks and GHG emission reduction claims. Non-compliance with these new laws may result in the imposition of substantial fines or penalties. Other states are considering similar laws. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, increased compliance costs resulting from the development of any disclosures, and increased costs of and restrictions on access to capital to the extent we do not meet any climate-related expectations or requirements of financial institutions.

Finally, some scientists have concluded that increasing concentrations of GHG emissions in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other extreme climatic events, as well as chronic shifts in temperature and precipitation patterns. Our offshore operations are particularly at risk from severe climatic events, which have the potential to cause physical damage to our assets and thus could have an adverse effect on our exploration and production operations. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. While our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

***Environmental Regulation in Shallow Waters Off the Coast of Mexico —*** Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the ASEA. We must obtain ASEA-issued permits and comply with ASEA regulations governing hydrocarbon activities, including requirements for environmental impact and risk assessments, industrial safety, waste management, water and air emissions, operational security and facility decommissioning. Failure to comply with applicable laws and regulations can result in the imposition of monetary penalties, revocation of permits, suspension of operations and ordered decommissioning of offshore facilities and systems. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are relatively new, having been significantly reformed following the establishment of ASEA in 2014 as a result of federal constitutional amendments approved in 2013, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our environmental compliance-related operating costs and/or capital expenditures for operations in Mexican offshore shallow waters.

For example, in May 2020, the ASEA published the Industrial Safety, Operational Safety and Environmental Protection Guidelines for the Closing, Dismantling and Abandonment of Hydrocarbons Sector Facilities (the "Dismantling Guidelines"). The Dismantling Guidelines are mandatory for all hydrocarbon sector facilities that perform dismantling, abandonment and closing of hydrocarbon sector activities. The Dismantling Guidelines set out several obligations in terms of safety, reporting and risk, including establishing a closing, dismantling and/or abandonment activities program for each of the relevant phases. Additionally, during the fourth quarter of 2021, ASEA announced its implementation of a "Popular Denunciation System" that will utilize an internet-based platform to allow persons, organizations and companies to anonymously report complaints against entities and companies operating in Mexico, including in respect of safety and environmental incidents such as, for example, hydrocarbon spills and pollution events. We anticipate that ASEA will conduct investigations to substantiate the incidents identified in the new reporting system.

Under the Block 7 PSC, we are jointly and severally liable for the performance of all obligations under the PSC, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSC.

***Federal Regulation of Sales and Transportation of Natural Gas*** — Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA") and by regulations and orders promulgated under the NGA and/or NGPA by the Federal Energy Regulatory Commission ("FERC"). In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the United States Congress and by FERC regulations. However, certain offshore gathering and transportation services we rely upon are subject to limited FERC regulation and are regulated by the states.

Pursuant to authority delegated to it by the Energy Policy Act of 2005 ("EPAct 2005"), FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms that make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to (i) use or employ any device, scheme or artifice to defraud, (ii) make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading or (iii) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The EPAct 2005 also amended the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and regulations, up to $1,544,521 per violation, per day for 2024 (this amount is adjusted annually for inflation). FERC may also order disgorgement of profits and corrective action. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes annual reporting requirements for entities that purchase or sell a certain volume of natural gas in a given calendar year. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of oil and natural gas are also subject to market manipulation and anti-disruptive requirements under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), and regulations promulgated thereunder by the U.S. Commodity Futures Trading Commission (the "CFTC"). The CFTC prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by the United States Congress, the applicable federal agencies, or the various state legislatures, and what effect, if any, the proposals might have on our operations. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. However, we are subject to reporting requirements imposed by FERC. There is always some risk, however, that the United States Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines or impose additional reporting or other requirements upon our operations, and we cannot predict what future action FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by FERC and the United States Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

***Federal Regulation of Sales and Transportation of Crude Oil*** — FERC regulates the interstate pipeline of crude oil, petroleum products and other liquids, such as NGLs. Our sales of crude oil and condensate are currently not regulated and are made at negotiated prices. There is always some risk, however, that the United States Congress may reenact crude oil, petroleum products and NGL price controls in the future. We cannot predict whether new legislation to regulate crude oil, or the prices charged for crude oil might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirements.

Our ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"), and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. Certain regulations implemented by FERC in recent years and certain pending rulemaking and other proceedings could result in an increase in the cost of transportation service on certain petroleum products pipelines. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other crude oil and condensate producers with which we compete.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to other crude oil and condensate producers with which we compete.

We own an undivided interest in a pipeline that extends from South Pass Block 89 in federal waters, offshore Louisiana, to the West Delta Receiving Station in Venice, Louisiana. Although the pipeline is subject to FERC jurisdiction under the ICA, FERC has granted us a temporary waiver of the filing and reporting requirements. If the facts upon which the waiver was granted change materially, we are required to inform FERC, which may result in revocation of the waiver. If conditions change such that the pipeline no longer qualifies for a waiver, we may be subject to regulation by FERC of the rates, terms and conditions of service on the pipeline; however, these burdens generally would not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar pipelines.

FERC also implements the OCSLA pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the OCS provide nondiscriminatory transportation service. We own and operate pipelines that are located in the OCS and are subject to the non-discrimination requirements in the OCSLA.

## Human Capital

We have experienced significant growth in our workforce since our formation as a private equity backed start-up company with six (6) original employees in 2012 to a NYSE publicly listed company with approximately 600 employees as of December 31, 2023. Our approach to human capital management has adapted as we have matured as a company and continues to evolve as we grow our business. We strive to manage our employees in a way that supports our business strategy, underscores our entrepreneurial spirit and promotes employee development.

***Policies*** — Our Code of Business Conduct and Ethics addresses our commitment to providing equal opportunities in employment without regard to race, color, gender identity or expression, religion, age, national origin, citizenship status, military service or reserve or veteran status, sexual orientation, or disability. We make employment and compensation decisions based on a person's ability to perform the tasks required by their position.

Our Human Rights Policy embodies key tenets which we expect all individuals involved in our operations to follow, such as respect for human rights; freedom of association and collective bargaining; freedom of religion, opinion, and assembly; maintaining a safe and healthy workplace; the prohibition of forced labor; prevention of human trafficking and child labor; right to a living wage; and open communication to report violations to the appropriate individuals.

Each of our Code of Business Conduct and Ethics and Human Rights Policy is overseen at the highest level by our Board of Directors (our "Board" or "Board of Directors").

Please refer to https://www.talosenergy.com/investor-relations/Corporate-Governance-New on our website for additional information regarding our corporate policies. The policies referenced herein, and the information contained on or accessible through our website, are not incorporated by reference herein or otherwise made a part of this Annual Report or any of our other filings with the SEC.

***Oversight and Management*** — The Company's executive leadership team, with oversight from various committees of the Board, sets the Company's human capital management philosophy and goals with the support of the human resources function which administers the Company's workforce programs.

The Compensation Committee of our Board (the "Compensation Committee") provides oversight, subject to Board approval, of the Company's executive compensation program, the annual incentive plan ("AIP"), the long-term incentive plan, and the overall budget for non-executive compensation. In addition, the Compensation Committee evaluates material risks related to the Company's compensation policies and practices. The Compensation Committee also periodically assesses the Company's compensation programs related to all employees.

The Nominating & Governance Committee of our Board (the "NGC") reviews succession planning for the Chief Executive Officer position, monitors and reviews the development and progression of potential successors and consults with the Chief Executive Officer on senior management succession planning. The NGC reviews with management the Company's executive succession risks.

The Safety, Sustainability and Corporate Responsibility Committee of our Board (the "SSCR Committee") reviews the Company's strategies, policies and procedures related to material safety matters, and reviews the Company's major operational risks, environmental, health and safety risks, climate change and other sustainability risks, social and human capital risks, including the welfare of employees in the workplace, and the Company's safety statistics, such as the Total Recordable Incident Rate and Significant Injury or Fatality Rate.

At the corporate level, the Vice President of Human Resources, together with our executive leadership team, is responsible for our workforce management policies and programs, reporting directly to our President and Chief Executive Officer ("CEO"), and providing regular updates to the Compensation, NCG, and SSCR Committees on human capital matters. Our President and CEO and other executive officers are accessible to all employees through town hall meetings where our President and CEO discusses corporate matters and other topics pertinent to employees, answers questions and receives employee feedback.

***Workforce Composition*** — As of December 31, 2023, we employed approximately 600 employees located primarily in Texas, Louisiana and Mexico, approximately 320 (53%) of which are employed in our offshore operations and seven (7) of which are Mexican nationals. In addition, we supplement our workforce with independent contractors and consultants to perform various offshore and corporate services. None of our employees are represented by labor unions or covered by any collective bargaining agreement.

***Safety*** — "Embody Integrity and Safety" is a core value and our number one priority in the operation of our business. Our focus on safety starts at the top with our Board of Directors, our President and CEO, our Executive Vice President and Head of Operations, who is directly responsible for all safety initiatives, and our Vice President of HSE, Regulatory and Compliance, who is dedicated exclusively to health, safety, and environmental matters. Workforce safety is also a key focus within our enterprise risk management assessment. Our Safety and Environmental Management System includes a stringent "Stop Work Authority" which empowers all employees and contractors to stop work immediately for any safety or environmental concern without fear of retaliation or intimidation. In addition, our behavior-based safety program and our "Keystones to Saving Lives" program are core components for effective pre-work planning and maintaining a safety-focused culture. We seek to reinforce our safety-first mindset by linking employees' compensation to safety performance through our annual bonus plan. Offshore employees are eligible to receive an additional quarterly safety bonus based on safety results at our offshore facilities. Please refer to our 2023 Sustainability Report posted on our website for information regarding our safety governance, programs and performance.

***Recruitment, Development and Leadership Training*** — We take a broad approach to recruiting top talent, utilizing online recruiting platforms, referrals, universities and colleges, internships and professional recruiters to access a skilled candidate pool. We encourage employee development through an interactive performance management process to provide feedback and growth opportunities that enable employees to advance their careers and support Talos's strategic business goals. In 2022, we launched the Leadership Development Program available to all employees with the goal of fostering dynamic and engaged leaders. In 2023, approximately 200 employees participated in this leadership training. We also reimburse for outside training and tuition for approved higher education in further support of developing our employees.

***Compensation and Benefits*** — Our success is based on our financial performance and operational results, and we believe that our compensation program is an important driver of these goals. Our program is designed to tie compensation to corporate and individual performance and align the interests of our employees with those of our stockholders. All full-time employees are eligible for our AIP focused on attaining financial, operational and strategic goals. We also utilize long-term incentive awards to motivate and retain key talent. Please refer to the section entitled "Compensation Discussion and Analysis" in our Definitive Proxy Statement on Form DEF 14A filed with the SEC on April 5, 2023, for further compensation information on our executive compensation program and philosophy.

We also seek to attract and retain employees by offering a broad array of health and welfare benefit programs designed to meet the needs of a varied workforce. In addition, we offer matching contributions to 401(k) accounts, a company health savings account contribution, subsidized counseling, legal and financial support, a subsidy for health & fitness memberships, paid time off and leave of absence, and a work-from-home program. We also began offering a mental health plan in 2023 to support employees and their families' mental well-being. In 2024, we expect to open an employee health clinic in our corporate offices to provide easy access for basic health needs.

***Social Investment*** — We support our employees and the communities where we live and work through active corporate philanthropic efforts. Our employee-led community committee supports outreach programs, fundraising efforts, and community involvement events to benefit charitable organizations. In addition, we (i) provide an annual allowance to every employee that can be donated to a charitable organization of their choice, (ii) match funds raised by community committee events, (iii) budget for corporate contributions to charitable organizations and (iv) provide a paid volunteer day off for each employee each year.

**Available Information**

We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, all amendments to those reports, and all other information filed with or furnished to the SEC available, free of charge, through our website, https://www.talosenergy.com, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. The filings are also available by accessing the SEC's website at https://www.sec.gov.

We voluntarily publish annual sustainability reports which are available free of charge on our corporate website at: https://www.talosenergy.com/sustainability/. Information included in these sustainability reports is not incorporated into this Annual Report or in any other report or document we file with the SEC.

## Item 1A. Risk Factors

Certain factors may have a material adverse effect on our business, financial condition, and results of operations. You should consider carefully the risks and uncertainties described below, in addition to other information contained in this Annual Report, including our Consolidated Financial Statements and related notes. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently believe are not material, may also become important factors that adversely affect our business. If any of the following risks actually occur, our business, financial condition, results of operations and future prospects could be materially and adversely affected. In that event, the trading price of our common stock could decline, and you could lose part or all of your investment.

### Risks Related to our Business and the Oil and Natural Gas Industry

***Oil and natural gas prices are volatile. Stagnation or declines in commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and available borrowings under our Bank Credit Facility and our ability to grow.***

Our revenues, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Prices affect our cash flows available for capital expenditures and our ability to access funds under our Bank Credit Facility and through the capital markets. The amount available for borrowing under our Bank Credit Facility is subject to a borrowing base, which is determined by the lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models to be determined by the lenders at such time. Further, because we use the full cost method of accounting for our oil and gas operations, we perform a ceiling test each quarter, and the risk that we are required to write-down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, or if estimated future development costs increase. Volatility in commodity prices, poor conditions in the global economic markets and other factors could cause us to record additional write-downs of our oil and natural gas properties and other assets in the future, and incur additional charges against future earnings. Any required write-downs or impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

In addition, significant or extended price declines may also adversely affect the amount of oil and natural gas that we can economically produce. A reduction in production and/or the prices we receive for our production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. For example, during the period January 1, 2021 through December 31, 2023, the daily NYMEX WTI crude oil price per Bbl ranged from a low of $47.47 to a high of $123.64, and the daily NYMEX Henry Hub natural gas price per MMBtu ranged from a low of $1.74 to a high of $23.86. Subsequent to December 31, 2023, NYMEX WTI crude oil and NYMEX Henry Hub natural gas prices recorded daily lows of $70.62 per Bbl and $1.61 per MMBtu, respectively.

The prices we receive for our oil and natural gas depend upon many factors beyond our control, including, among others:

- changes in domestic and global supply of and demand for oil and natural gas;
- market uncertainty;
- level of consumer product demands;
- the cost of exploring for, developing and producing oil and natural gas;
- changes in climate, weather and natural disasters such as hurricanes and other adverse climatic conditions;
- the impact of applicable market differentials, including those relating to quality, transportation, fees, energy content and regional pricing;
- domestic and foreign governmental actions, regulations and taxes;
- price and availability of alternative fuels and competing forms of energy;
- political and economic conditions in oil and natural gas producing regions, particularly in the Middle East, Russia, South America and Africa;
- armed conflicts and hostilities such as Russia’s ongoing war in Ukraine and increasing hostilities in Israel and the Middle East;
- the occurrence or threat of epidemic or pandemic diseases and other public health events;

- actions by OPEC Plus and other significant producers and governments relating to oil and natural gas price and production controls;
- volatility in the political, legal and regulatory environments ahead of the upcoming U.S. and Mexico presidential elections;
- U.S. and foreign supply of oil and natural gas;
- price and quantity of oil and natural gas imports and exports;
- the level of global oil and natural gas exploration and production and inventories;
- localized supply and demand fundamentals and transportation availability;
- infrastructure availability and constraints such as capacity of processing, gathering, storage and transportation facilities;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- overall economic conditions worldwide.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because oil, natural gas and NGLs accounted for approximately 73%, 20%, and 7%, respectively, of our estimated proved reserves as of December 31, 2023, and approximately 75%, 18%, and 7%, respectively, of our 2023 production on an MBoe basis, our financial results are sensitive to movements in oil, natural gas and NGL prices.

***Future exploration and drilling results are uncertain and involve substantial costs.***

Drilling for oil and natural gas involves numerous risks including the risk that we may not encounter commercially productive reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- inflation in exploration and drilling costs;
- fires, explosions, blowouts or surface cratering;
- lack of, or disruption in, access to infrastructure and transportation;
- lack of available skilled labor; and
- shortages or delays in the availability of services or delivery of equipment.

***Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic region, making us vulnerable to risks associated with operating in one geographic area.***

We currently operate in a concentrated geographic region, in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. As such, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions such as:

- severe weather, such as hurricanes, winter storms, loop currents, tornadoes and other adverse climatic conditions;
- changes in state or regional laws and regulations affecting our operations (including regulations that may, in certain circumstances, impose strict liability for pollution damage or require posting substantial bonds to address decommissioning and P&A costs) and interruption or termination of operations by governmental authorities based on environmental, safety or other considerations;
- local price fluctuations and other regional supply and demand factors, including availability of gathering, pipeline, transportation and storage capacity constraints;
- production delays or decreases in the region;

- limited potential customers;
- infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- changes in guidelines issued by BOEM related to financial assurance requirements to cover decommissioning obligations for operations on the OCS; and/or
- changes imposed as a result of litigation or by a new presidential administration or by Congress in the United States that may result in added restrictions and delays or prohibitions in offshore oil and natural gas exploration and production activities, including with respect to leasing, permitting, site development or operation in federal waters or hydraulic fracturing.

Because all or a number of our properties could experience many of the same conditions at the same time, these conditions may have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

***Production periods or relatively short reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.***

Substantially all of our operations are in the U.S. Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other companies with longer-life reserves in other producing areas. Our future oil and natural gas production is highly dependent upon finding and/or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices.

Exploring for, developing or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop or acquire additional reserves or make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. Our need to generate revenues to fund ongoing capital commitments and/or repay debt may limit our ability to slow or shut-in production from producing wells during periods of low prices for oil and natural gas. We cannot assure you that our future exploitation, exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, current market conditions may adversely impact our ability to obtain financing to fund acquisitions, and further lower the level of activity and depressed values in the oil and natural gas property sales market.

***Our actual recovery of reserves may substantially differ from our proved reserve estimates.***

Reserve estimation is a subjective and complex process that requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data to estimate volumes to be recovered from underground accumulations of oil and natural gas that cannot be directly measured. These estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance in these factors could materially affect the estimated quantities and present value of reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. See Part I, Items 1 and 2. Business and Properties—Summary of Reserves for further discussion on 2023 changes in estimates of our proved reserves.

You should not assume that any present value of future net cash flows from our proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2023 on historical 12-month average prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues are affected by factors such as:

- the amount and timing of capital expenditures and decommissioning costs;
- the rate and timing of production;
- changes in governmental legislation, regulations or taxation;
- volume, pricing and duration of our oil and natural gas hedging contracts;
- supply of and demand for oil and natural gas;

- actual prices we receive for oil and natural gas; and
- our actual operating costs in producing oil and natural gas.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from reserves, and thus their actual present value. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and natural gas industry in general.

At December 31, 2023, approximately 14% of our estimated proved reserves (by volume) were undeveloped and approximately 23% were non-producing. Any or all of our PUD or proved developed non-producing reserves may not be ultimately developed or produced. Furthermore, any or all of our undeveloped and developed non-producing reserves may not be ultimately produced during the time periods we plan or at the costs we budget, which could result in the write-off of previously recognized reserves. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling or waterflood operations. Our reserve estimates include the assumptions that we incur capital expenditures to develop these undeveloped reserves and the actual costs and results associated with these properties may not be as estimated. Any material inaccuracies in these reserve estimates or underlying assumptions materially affects the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

***Our acreage must be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.***

Our leases may expire unless production is established as required by leases covering undeveloped acres. Our drilling plans for areas not held by production are subject to change based upon various factors. As of December 31, 2023, approximately 53% of our net acreage was undeveloped acres. See Part I, Items 1 and 2. Business and Properties—Acreage for further discussion. Many of these factors are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On the acreage that we do not operate, we have less control over the timing of drilling, and therefore there is additional risk of expirations occurring in those acreages.

***The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.***

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and natural gas gathering systems, pipelines and processing facilities. The lack of availability or capacity of this infrastructure could result in the shut-in of producing wells or delays or discontinuance of development plans for our properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. Federal, state, and local regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors change dramatically, the financial impact could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

***Inflationary issues and associated changes in monetary policy may result in increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.***

The U.S. inflation rate steadily rose in 2021 and into 2022 before eventually declining throughout 2023. These inflationary pressures resulted in increases to the costs of our goods, services and personnel, which in turn, caused our capital expenditures and operating costs to rise. The U.S. Federal Reserve (the “Fed”) and other central banks increased interest rates multiple times in 2022 and 2023 in an effort to curb inflationary pressure on the costs of goods and services across the U.S. and globally. While the Fed indicated in December 2023 that it may reduce benchmark interest rates in 2024, the continuation of elevated rates 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.

Higher crude oil and natural gas prices may cause the costs of materials and services to continue to rise. We cannot predict any future trends in the rate of inflation or the monetary policies in response thereto.

***We may be unable to pursue our CCS business, either wholly or in significant measure, which could have a material adverse effect on our business, results of operations and financial condition.***

The successful development of our CCS projects is dependent on various economic, regulatory, operational and technical factors. The failure to satisfy, wholly or in significant measure, any of such factors could have a material adverse impact on our business, results of operations and financial condition.

Risks related to our CCS business include but are not limited to:

- the uncertainty of evolving government regulations;
- adequate capital financing to develop our projects;
- the availability of necessary infrastructure, equipment, services and skilled personnel to develop our CCS business;
- sufficient infrastructure to capture $CO_2$ at the source, and transport it to CCS sites;
- the availability, applicability and adequacy of various federal and state incentive programs related to CCS projects;
- the availability and cost of acquiring necessary federal and state permits, including permits applicable to subsurface injection, and air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility;
- our ability to maintain adequate financial assurances to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response;
- public and political opinion regarding CCS development in local communities;
- locating suitable sources of anthropogenic $CO_2$;
- obtaining sufficient quantities of $CO_2$ from, and entering into suitable agreements with, emitters on terms that are acceptable and economical to us; and
- complex recordkeeping and GHG emissions/sequestration accounting which may increase our costs.

The availability and applicability of various federal financial incentives related to our projects is uncertain and there is no assurance that if available, such incentives would be adequate for our CCS project needs or that such incentives will continue to be available in the future.

Additionally, successful development of CCS projects in the United States requires us to comply with stringent and varied regulatory schemes requiring permits applicable to subsurface injection of $CO_2$ for geologic sequestration. Moreover, as operator for two of our CCS projects, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. As carbon management represents an emerging sector, regulations may evolve rapidly and unpredictably, which could impact the feasibility of one or more of our anticipated projects. There is no assurance that we will be successful in obtaining sufficient federal and state permits or adequate levels of financial assurance for one or more of our CCS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition or otherwise. Separately, CCS projects are also subject to additional permits and approvals unrelated to subsurface injection from various U.S. federal and state agencies, such as for air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility. To the extent regulatory requirements are imposed, are increased or more stringently enforced, we may incur additional costs in the development of our CCS projects, which costs may be material or may render any one or more of our projects uneconomic.

CCS projects also require satisfying certain operational factors, such as locating a suitable source of anthropogenic $CO_2$ and reaching suitable agreements to capture that $CO_2$. Such agreements are complex and may involve allocation of not only fees but also various credits, incentives and environmental attributes associated with the sequestration of $CO_2$. Not all emission sources produce sufficiently large quantities of pure or relatively pure streams of $CO_2$, or have installed equipment to capture such $CO_2$, so as to be usable in one or more of our CCS projects. As a result, we may not be able to obtain sufficient quantities of $CO_2$ from emitters on terms that are acceptable to us, and the failure to do so may have a material impact on our ability to execute our CCS strategy. Additionally, development of successful CCS projects will require infrastructure to transport $CO_2$ between the source and our CCS sites. In project areas with existing $CO_2$ transportation pipelines, this may require reaching an agreement on $CO_2$ transportation with operators of $CO_2$ pipelines within the regions in which we operate. Inability to reach a suitable agreement may render a project uneconomic or impracticable.

Separately, if no $CO_2$ pipelines exist in proposed project areas, or if existing pipelines do not extend to one or more of our project sites, we may be required to convert existing pipelines, or build new $CO_2$ pipelines or lateral connections, which may be subject to various environmental and other permitting requirements to include increased regulation from U.S. federal and state agencies, as well as third party easements, which may render one or more projects uneconomical. We will also need to build the required equipment on a timely basis and at a cost that is economically viable. Additionally, complex recordkeeping and GHG emissions/sequestration accounting may be required in connection with one or more of our projects, which may increase the costs of such operations. Different methodologies may be required for various regulatory and non-regulatory accounts regarding GHG emissions/sequestration at one or more of our projects, including but not limited to, compliance with the EPA's mandatory Greenhouse Gas Reporting Program. Furthermore, as CCS may be viewed as a pathway to the continued use of fossil fuels, notwithstanding that $CO_2$ emissions are intended to be captured, there may be organized opposition to CCS, including as it relates to our projects.

We can provide no assurance that we will be able to execute our CCS business strategy in the future. Any failure by us to achieve such expectations in whole or any significant measure could have a material adverse effect on our business, results of operations and financial condition.

***Our inability to benefit from Section 45Q tax credits could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition.***

The successful development of our CCS projects is dependent upon our ability to benefit from certain financial and tax incentives available with respect to CCS projects. The development of CCS projects is incentivized by tax credits provided under Section 45Q of the Internal Revenue Code of 1986, as amended (such credits, "Section 45Q tax credits"), which provides a tax credit for qualified $CO_2$ that is captured using carbon capture equipment and disposed of in secure geological storage. The amount of Section 45Q tax credits from which we may benefit is dependent upon our ability to satisfy certain wage and apprenticeship requirements, which we cannot assure you that we will satisfy. With respect to the first five tax years a qualifying CCS project is in service, but not beyond December 31, 2032, we may elect a "direct pay" option with respect to available Section 45Q tax credits to efficiently monetize their value (i.e., we may receive a payment for the tax credits through a tax refund as if there had been an overpayment of taxes). Following the period in which the direct pay election is available and for the remaining period in which the applicable Section 45Q tax credits are otherwise available, we may elect to transfer the Section 45Q tax credits to unrelated taxpayers. We cannot assure you that we will be able to efficiently monetize Section 45Q tax credits that are transferred to unrelated taxpayers. We will benefit from Section 45Q tax credits only if we satisfy the applicable statutory and regulatory requirements for obtaining the Section 45Q tax credits, including that we own carbon capture equipment that captures qualified $CO_2$ that we physically or contractually capture and securely store, or if another party that owns carbon capture equipment elects to pass through Section 45Q tax credits to us, that we dispose of the qualified $CO_2$ in secure storage. If we are unable to satisfy such statutory and regulatory requirements or otherwise qualify for or obtain the Section 45Q tax credits, our CCS projects may no longer be economically viable and may not be completed. We cannot assure you that we will be successful in satisfying such requirements or otherwise qualifying for or obtaining the Section 45Q tax credits currently available or that we will be able to effectively benefit from such tax credits. Section 45Q tax credits are also subject to recapture with respect to any $CO_2$ that ceases to be disposed of in secure storage, which recapture is treated as an increase in tax liability for the year in which the recapture occurs. The recapture period for Section 45Q tax credits is limited to a 3-year lookback period preceding the date that sequestered $CO_2$ escapes from its secure storage.

Additionally, the availability of Section 45Q tax credits may be reduced, modified or eliminated as a matter of legislative or regulatory policy. There can be no assurance that Section 45Q tax credits will not be reduced, modified or eliminated in the future, including as a result of any change in presidential administration as a result of the 2024 U.S. presidential election. Any such reduction, modification or elimination of Section 45Q tax credits, or our inability to otherwise benefit from Section 45Q tax credits, could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition. Even if we are able to benefit from Section 45Q tax credits, we may determine that additional financial incentives are required for our CCS projects to be economically viable. If such additional incentives do not emerge, we may not be able to achieve an economic return from our CCS business or, alternatively, the construction or operation of our CCS projects may be substantially delayed, unprofitable or otherwise infeasible.

***We may be unable to provide the financial assurances in the amounts and under the time periods required by BOEM if it submits future demands to cover our decommissioning obligations. If in the future BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our associated federal offshore leases.***

BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In 2016, BOEM under the Obama Administration had sought to implement more stringent and costly standards under the existing federal financial assurance requirements through issuance and implementation of the 2016 NTL, but the Trump Administration first suspended, and then in 2020 rescinded, the implementation of the 2016 NTL. Following the effectiveness of the 2016 NTL, we received orders from BOEM in late 2016 directing us to provide additional financial assurance in material amounts relating to our OCS properties. We entered into discussions with BOEM regarding the requested additional financial security and submitted a proposed tailored plan (applicable to our sole and non-sole liability properties) for the posting of additional financial security to the agency for review. However, as the Trump Administration rescinded the 2016 NTL, BOEM withdrew the previously issued orders under the 2016 NTL.

In August 2021, BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM. In connection with this Note to Stakeholders, BOEM initially assessed the required financial assurance for our sole liability properties as approximately $70 million. However, following the opportunity to review BOEM's sole liability assessment, we were able to reduce the financial assurance required to approximately $37.7 million. The bonds covering this amount were posted in 2021. Notwithstanding the above, BOEM, now under the Biden Administration, could, in the future, continue to make new demands for additional financial assurances in material amounts relating to the decommissioning of our OCS properties. BOEM may reject our proposals to satisfy any such additional financial assurance coverage and make demands that exceed our capabilities.

If we fail to comply with the current or future orders of BOEM to provide additional surety bonds or other financial assurances, BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel leases associated with our noncompliance, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. BOEM has the right to issue financial assurance orders in the future, including if it determines there is a substantial risk of nonperformance of the current interest holder's decommissioning liabilities and the Biden Administration may elect to pursue more stringent supplemental bonding requirements.

In the event that BOEM finalizes new regulations similar to or more stringent than the 2016 NTL, such as BOEM's June 2023 proposed rule that substantially revises the supplemental financial assurance requirements applicable to offshore oil and gas operations, the surety bond market has very limited capacity to provide additional financial assurance and we therefore may not be able to procure and provide the financial assurance required by such new regulations. Moreover, the implementation of such new regulations could result in sureties seeking additional collateral to support existing or future bonds, such as cash or letters of credit, and we cannot provide assurance that we will be able to satisfy collateral demands for such bonds to comply with supplemental bonding requirements of BOEM. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be negatively impacted and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures. All of these factors may make it more difficult for us to obtain the financial assurances required by BOEM to conduct operations on the OCS. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations, reduced cash flows if unable to comply and consequently have a material adverse effect on our business and results of operations.

See Part I, Items 1 and 2. Business and Properties — Government Regulation — Outer Continental Shelf ("OCS") Regulation for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry on the OCS.

***Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.***

As an oil and gas producer, we have various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business. In particular, the implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls are sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems 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. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments subject our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers or vendors, could have a material adverse effect on our financial condition and operations.

***Global geopolitical tensions may create heightened volatility in oil, gas and NGL prices and could adversely affect our business, financial condition and results of operations.***

Our oil and gas activities are subject to numerous geopolitical and economic risks, uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases, and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to acts of terrorism, piracy, disease, illegal cartel activities and other political risks, including tension and confrontations among political parties. The upcoming presidential election in the U.S., the expected change in presidential administration in Mexico, the extended war between Russia and Ukraine and increasing hostilities in the Middle East may cause prolonged uncertainty and volatility in commodity prices.

Mexico's most recent presidential election was held in July 2018. Presidential reelection is not permitted in Mexico. President Andrés Manuel López Obrador, took office on December 1, 2018, and his successor is due to be elected in June of 2024. At this time we cannot predict what changes (if any) will result from this change in administration. Political events in Mexico could adversely affect economic conditions and/or the oil and gas industry and, by extension, our results of operations and financial position.

On February 24, 2022, Russian military forces invaded Ukraine, and sustained war and continued and prolonged disruption in the region is likely.

Russia's recognition of two separatist republics in the Donetsk and Luhansk regions of Ukraine and subsequent military action against Ukraine have led to an unprecedented expansion of sanction programs imposed by the U.S., the European Union, the United Kingdom, Canada, Switzerland, Japan and other countries against Russia, Belarus, the Crimea Region of Ukraine, the so-called Donetsk People's Republic and the so-called Luhansk People's Republic, including, among others:

- blocking sanctions against some of the largest state-owned and private Russian financial institutions (and their subsequent removal from the Society for Worldwide Interbank Financial Telecommunication payment system) and certain Russian businesses, some of which have significant financial and trade ties to the European Union;
- blocking sanctions against Russian and Belarusian individuals, including the Russian President, other politicians and those with government connections or involved in Russian military activities; and
- blocking of Russia's foreign currency reserves as well as expansion of sectoral sanctions and export and trade restrictions, limitations on investments and access to capital markets and bans on various Russian imports.

In retaliation against new international sanctions and as part of measures to stabilize and support the volatile Russian financial and currency markets, the Russian authorities also imposed significant currency control measures aimed at restricting the outflow of foreign currency and capital from Russia, imposed various restrictions on transacting with non-Russian parties, banned exports of various products and other economic and financial restrictions. The situation is rapidly evolving as a result of the war in Ukraine, and the U.S., the European Union, the United Kingdom and other countries may implement additional sanctions, export controls or other measures against Russia, Belarus and other countries, regions, officials, individuals or industries in the respective territories. Such sanctions and other measures, as well as the existing and potential further responses from Russia or other countries to such sanctions, tensions and military actions, could adversely affect the global economy and financial markets and could adversely affect our business, financial condition and results of operations.

We are actively monitoring the situation in Ukraine and assessing its impact on our business, including our business partners and customers. To date we have not experienced any material interruptions in our infrastructure, supplies, technology systems or networks needed to support our operations. We have no way to predict the progress or outcome of the war in Ukraine or its impacts in Ukraine, Russia or Belarus as the war, and any resulting government reactions, are rapidly developing and beyond our control. Continued hostilities, or any significant increases in the extent and duration of the military action, sanctions and resulting market disruptions — or any meaningful escalation in the objectives thereof or the methods used by the combatants to achieve such objectives —could be significant and could potentially have substantial impact on the global economy and our business for an unknown period of time.

Alternatively, a cessation of hostilities as a result of a negotiated withdrawal or otherwise—particularly if coupled with an easing of international sanctions — could cause commodity prices to decline in a manner that would reduce the revenues we receive for our oil and gas production. During the first quarter of 2022, we experienced an increase in commodity prices as sanctions imposed on Russia severely limited the access of Russian oil and gas producers to international markets. In the months that followed, commodity prices subsequently decreased and remained stagnant during the second half of 2022. If the military action concludes and the related sanctions are dropped, commodity prices could significantly decrease. Any of the above mentioned factors could affect our business, financial condition and results of operations.

Additionally, on October 7, 2023, Hamas, a U.S.-designated terrorist organization, launched a series of coordinated attacks from the Gaza Strip onto Israel. On October 8, 2023, Israel formally declared war on Hamas, and the armed conflict is ongoing as of the date of this filing. Hostilities between Israel and Hamas have escalated and involved surrounding countries in the Middle East. Iranian-backed groups have launched attacks on U.S. military bases and assets in Syria, Iraq, and Jordan, and have targeted international shipping in the Red Sea. After three American troops were killed in a drone attack by an Iran-backed militant group, the U.S. launched retaliatory strikes on multiple sites in Iraq and Syria used by Iranian forces and Iran-backed militants. U.S. and British forces then launched a series of strikes on Houthi targets in Yemen in response to continuing attacks on shipping in the Red Sea and Gulf of Aden. Although the length, impact and outcome of the military conflicts between Ukraine and Russia and Israel and Hamas, respectively, are highly unpredictable, these conflicts could lead to significant market and other disruptions, including significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, political and social instability and other material and adverse effects on macroeconomic conditions. It is not possible at this time to predict or determine the ultimate consequence of these regional conflicts. These conflicts and their broader impacts could adversely affect our business, financial condition and results of operations and the global economy.

***We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.***

As we carry out our drilling program, we may not serve as operator of all planned wells. For example, in March 2022, the final UR from SENER regarding the development of the Zama Field in offshore Mexico, affirmed the appointment of PEMEX as operator of the unit, despite our discovery of the Zama Field in 2017 and subsequent operatorship. We may have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners, and our limited ability to influence operations and associated costs of properties operated by others, could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depends upon a number of factors that could be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise and financial resources;
- approval of other participants in drilling wells;
- risk of other non-operator’s failure to pay its share of costs, which may require us to pay our proportionate share of the defaulting party’s share of costs;

- selection of technology;
- the rate of production of the reserves; and
- the timing and cost of P&A operations.

In addition, with respect to oil and natural gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we would prefer;
- delay the pace of exploratory drilling or development; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

***Hedging transactions may limit our potential gains.***

In order to manage our exposure to price risks in the marketing of our oil, natural gas and NGLs, we periodically enter into oil, natural gas and NGL price hedging arrangements with respect to a portion of our expected production. These arrangements may include futures contracts on the NYMEX. While intended to reduce the effects of volatile oil and natural gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected or is shut-in for extended periods due to hurricanes or other factors;
- there is a widening of price differentials between delivery points for our production and the delivery point to be assumed in the hedge arrangement;
- the counterparties to our futures contracts fails to perform the contracts;
- a sudden, unexpected event materially impacts oil or natural gas prices; or
- we are unable to market our production in a manner contemplated when entering into the hedge contract.

Our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our Bank Credit Facility. Our derivative agreements with the lenders are secured by the security documents executed by the parties under the Bank Credit Facility. Future collateral requirements for our commodity hedging activities are uncertain and depend on the arrangements we negotiate with the counterparty and the volatility of oil and natural gas prices and market conditions.

***Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine life and endangered and threatened species.***

Our oil and natural gas operations in the United States and Mexico are subject to stringent federal, state and/or local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations require permits or other approvals before drilling or other regulated activity commences; restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; limit or prohibit exploration or drilling activities on certain lands lying within protected areas or that may affect certain wildlife, including marine species and endangered and threatened species and impose substantial liabilities for pollution resulting from our operations. Additionally, the threat of climate change continues to be a heightened area of focus and regulatory and disclosure requirements in the United States. For example, in March 2022, the SEC proposed rules which could require additional disclosure of climate change-related information, including, among other things, climate change risk management; short-medium-and long-term climate-related financial risks; and reporting Scope1, Scope2 and (for certain companies) Scope3 emissions. The SEC's proposed climate disclosure rules have not yet been finalized, but implementation of the rules as proposed could impose additional costly and time-consuming requirements on our business. For additional information about government regulation related to environmental and worker safety matters, please see Part I, Items 1 and 2. Business and Properties — Government Regulation — Environmental and Occupational Safety and Health Regulations. Any regulatory developments that impact, curtail or increase the cost of our oil and natural gas exploration and production activities on the OCS could have a material adverse effect on our business, results of operations and financial condition.

***Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.***

The Biden Administration has taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations and those of the oil and gas industry more generally. The Biden Administration issued the "Executive Order on Tackling the Climate Crisis at Home and Abroad" on January 27, 2021 (the "Climate Change Executive Order"). This executive order directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending completion of a review by the Secretary of the Interior of federal oil and gas permitting and leasing practices in light of the Biden Administration's concerns regarding the impact of these activities on the environment and climate. The Secretary of the Interior completed its review of permitting and leasing practices in November 2021 and issued a report recommending, among other things, an increase in royalty rates and financial assurance requirements. However, litigation concerning the Climate Change Executive Order's pause on new oil and gas leases is ongoing. In June 2021, the U.S. District Court for the Western District of Louisiana issued a nationwide preliminary injunction barring the Biden Administration from implementing the pause in new federal oil and gas leases, an injunction which was made permanent in August 2022. This effectively halts implementation of the leasing suspension with respect to those lease sales canceled or postponed prior to March 24, 2021. In November 2021, the Biden Administration conducted Lease Sale 257 and various industry participants submitted bids for leases in the Gulf of Mexico; however, on January 27, 2022, in litigation brought by Friends of the Earth and other plaintiffs, the U.S. District Court for the District of Columbia vacated Lease Sale 257 and the related agency decision making process, finding that BOEM failed to consider the impact on foreign greenhouse gas emissions if Lease Sale 257 was not held and the court determined that this failure was a violation of the NEPA. In September 2022, BOEM announced that it was reinstating Lease Sale 257 results in line with congressional direction in the IRA 2022. In addition, there is increasing uncertainty regarding the near-term future of Gulf of Mexico lease sales. These lease sales are conducted pursuant to Five-Year Leasing Programs under the Outer Continental Shelf Lands Act. The most recent Five-Year Leasing Program expired on June 30, 2022 and on July 1, 2022, BOEM released a proposed program for 2023 through 2028. The proposed program, which was subject to public comment through October 6, 2022, proposes no more than ten potential lease sales in the Gulf of Mexico. On September 29, 2023, the proposed final program for 2024-2029 was published and includes a maximum of three potential oil and gas lease sales in the Gulf of Mexico scheduled to be held in years 2025, 2027 and 2029. The Secretary of the Interior approved the 2024-2029 program via a combined decision memo and Record of Decision. It is likely, however, that the new Five-Year Leasing Program will be subject to heightened environmental review. It is also possible that the program could be delayed by opposing lawsuits that were filed on February 12, 2024 by the American Petroleum Institute and by Earthjustice representing multiple environmental groups both of which are challenging BOEM's actions. Future actions taken by the Biden Administration to limit the availability of new oil and gas leases on the OCS would adversely impact the offshore oil and gas industry and impact demand for our products.

Over the past decade, BSEE and BOEM, primarily under the Obama Administration, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. While actions by BSEE or BOEM under the Trump Administration sought to mitigate or delay certain of those more rigorous standards, the Biden Administration could reconsider rules and regulatory initiatives implemented under the previous administration and replace them with more stringent requirements and also provide more rigorous enforcement of existing regulatory requirements. For example, in August 2023, BSEE published a final rule, effective October 23, 2023, to clarify and modify certain blowout preventer system requirements. The rule requires, among other things, that the blowout preventer system is able to close and seal the wellbore at all times to the wells maximum kick tolerance design limits and includes more stringent requirements for failure reporting. Compliance with any added or more stringent regulatory requirements or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. Moreover, governmental agencies under the Biden Administration may continue evaluating aspects of safety and operational performance in the U. S. Gulf of Mexico that may result in new, more restrictive requirements.

These regulatory actions, or any new laws, executive orders, regulations or other legal or enforcement initiatives, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and associated costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States or other countries where such an event may occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling and production operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

See Part I, Items 1 and 2. Business and Properties — Government Regulation — Outer Continental Shelf ("OCS") Regulation for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry on the OCS.

***Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.***

Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as marine habitats, and restrictions on the way we can discharge materials and/or GHG emissions into the environment; bonds or other financial responsibility requirements to cover drilling contingencies, well P&A and other decommissioning costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; regulations regarding the rate, terms and conditions of transportation service or the price, terms, and conditions related to the purchase and sale of oil and natural gas; and taxation. Failure to comply with these laws and regulations can result in the assessment of administrative, civil or criminal penalties, the issuance of remedial obligations and the imposition of injunctions limiting or prohibiting certain of our operations. In addition, because we hold federal leases, the federal government requires that we comply with numerous additional regulations applicable to government contractors.

The SENER has promulgated guidelines to establish procedures for conducting the unitization of shared reservoirs and approving the terms and conditions of unitization and unit operating agreements, as well as the authority to direct parties holding rights in a potentially shared reservoir to appraise and potentially form a unit for development of such reservoir.

***If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.***

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. Any shut-in or curtailment of the oil, natural gas and NGLs produced from our fields could adversely affect our financial condition and results of operations.

***We may experience significant shut-ins and losses of production due to the effects of events outside of our control, including tropical storms and hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico and epidemics, outbreaks or other public health events.***

Our production is primarily associated with our properties in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. We are particularly vulnerable to significant risk from hurricanes, tropical storms, loop currents and other adverse weather conditions in the U.S. Gulf of Mexico. We are unable to predict what impact future incidents might have on our future results of operations and production.

Epidemics, pandemics, outbreaks or other public health events that are outside of our control could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by government and health authorities, including quarantines, to address an outbreak and (v) restrictions that we and our contractors, subcontractors and our customers impose, including facility shutdowns, to ensure the safety of employees.

***We are not insured against all of the operating risks to which our business is exposed.***

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational loss-related events. We have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, named U.S. Gulf of Mexico windstorm, oil pollution, construction risk, workers' compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that have to be met prior to recovery, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences, damages or losses. See Part I, Items 1 and 2. Business and Properties – Insurance Matters for more information on our insurance coverage.

An operational or hurricane or other adverse weather-related event may cause damage or liability in excess of our coverage that might severely impact our financial position. We may be liable for damages from an event relating to a project in which we own a non-operating working interest. Such events may also cause a significant interruption to our business, which might also severely impact our financial position. We may experience production interruptions for which we do not have production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the U.S. Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

***Our actual production could differ materially from our forecasts.***

From time to time, we may provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts may assume that none of the risks associated with our oil and natural gas operations summarized in this section would occur, such as facility or equipment malfunctions, adverse weather effects, adverse resolutions to disputes relating to operatorships or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

***Our operations are subject to numerous risks of oil and natural gas drilling and production activities.***

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves are found. The cost of drilling and completing wells is often uncertain. To the extent we drill additional wells in the U.S. Gulf of Mexico Deepwater and/or in the Gulf Coast deep shelf, our drilling activities increase capital cost. In addition, the geological complexity of the areas in which we have oil and natural gas operations make it more difficult for us to sustain the historical rates of drilling success. Oil and natural gas drilling and production activities may be shortened, delayed or cancelled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- hurricanes and other adverse weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. We cannot assure you that the wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry holes and wells that are productive but do not produce sufficient cash flows to recoup drilling costs.

In addition, an oil spill on or related to our properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for containment and oil removal costs and a variety of public and private damages, including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. If an oil discharge or substantial threat of discharge were to occur, we could be liable for costs and damages, which costs and damages could be material to our results of operations and financial position.

We have an interest in Deepwater fields and may attempt to pursue additional operational activity in the future and acquire additional fields and leases in the Deepwaters of the U.S. Gulf of Mexico. Exploration for oil or natural gas in the Deepwaters of the U.S. Gulf of Mexico generally involves greater operational and financial risks than exploration in the shallower waters of the U.S. Gulf of Mexico conventional shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. For example, the drilling of Deepwater wells requires specific types of drilling rigs with significantly higher day rates and limited availability as compared to the rigs used in shallower water. Deepwater wells often use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in cost overruns. Furthermore, the Deepwater operations generally lack the physical and oilfield service infrastructure present in the shallower waters of the U.S. Gulf of Mexico conventional shelf. As a result, a considerable amount of time may elapse between a Deepwater discovery and the marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the Deepwater may never be produced economically.

If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and production and repairs to resume operations. Any of these industry operating risks could have a material adverse effect on our business, results of operations and financial condition.

***Competition within our industry may adversely affect our operations. Many of our competitors are larger and have more available financial resources.***

The oil and gas industry is highly competitive, and many companies in our industry are larger and have substantially greater financial resources than we do. We compete with these companies for oil and natural gas leases and other properties; equipment and personnel; and marketing our product to end-users. Such competition can significantly increase costs and the availability of resources available to us, which could provide larger companies a competitive advantage. Larger competitors may also be able to more easily attract and retain experienced personnel. In addition, larger competitors may be better able to respond and adapt to adverse economic and industry conditions, including price fluctuations, reduced oil and gas demand, political changes and current and future governmental regulations and taxation.

Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to outbid us for acquisitions, productive oil and gas properties and exploratory prospects. Further, our competitors may be able to expend greater resources on the existing and changing technologies to gain competitive advantages. If we are unable to compete successfully in the future, our future revenues and growth may be diminished or restricted.

***The loss of our larger customers could materially reduce our revenue and materially adversely affect our business, financial condition and results of operations.***

We have a limited number of customers that provide a substantial portion of our revenue. The loss of our larger customers, including Shell Trading (US) Company and Valero Energy Corporation, could adversely affect our current and future revenue, and could have a material adverse effect on our business, financial condition and results of operations. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* for additional information.

***The loss of key personnel could adversely affect our ability to operate.***

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices. Our operations are dependent upon key management and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us and our operations.

In addition, our exploration, production and decommissioning activities require personnel with specialized skills and experience. As a result, our ability to remain productive and profitable depends upon our ability to employ and retain skilled workers. Our ability to expand operations depends in part on our ability to increase the size of our skilled labor force, including geologists and geophysicists, field operations managers and engineers, to handle all aspects of our exploration, production and decommissioning activities. The demand for skilled workers in our industry is high, and the supply is limited. A significant increase in the wages paid by competing employers or the unionization of our U.S. Gulf of Mexico employees could result in a reduction of our labor force, increases in the wage rates that we will have to pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

***We have operations in multiple jurisdictions, including jurisdictions in which the tax laws, their interpretation or their administration may change. As a result, our tax obligations and related filings are complex and subject to change, and our after-tax profitability could be lower than anticipated. Additionally, future tax legislative or regulatory changes in the United States, Mexico or any other jurisdiction in which we operate or have subsidiaries could result in changes to the taxation of our income and operations, which could also adversely impact our after-tax profitability.***

We are subject to income, withholding and other taxes in the United States on a worldwide basis and in numerous state, local and foreign jurisdictions with respect to our income, operations and subsidiaries in those jurisdictions. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions, refunds (including refunds of value added taxes) and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate or have subsidiaries, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing business structure and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions.

Our after-tax profitability may also be affected by changes in the relevant tax laws and tax rates, regulations, administrative practices and principles, judicial decisions, and interpretations, in each case, possibly with retroactive effect. From time to time, federal and state level legislation in the United States has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Such proposed legislative changes have included, but have not been limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies, and (v) an increase in the U.S. federal income tax rate applicable to corporations (such as us). U.S. states in which we operate or own assets may also impose new or increased taxes or fees on oil and natural gas extraction. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting (the "Multilateral Instrument") has entered into force among the jurisdictions that have ratified it, although the United States has not yet become a signatory to the Multilateral Instrument. Such proposed legislative changes and ratification of the Multilateral Instrument in the jurisdictions in which we operate could result in further changes to our global taxation. Additionally, Mexico has enacted tax reform legislation, and a majority of the provisions became effective on January 1, 2020. These tax reforms provided for new and complex provisions that significantly change how Mexico tax entities and operations and are subject to further legislative change and administrative guidance and interpretation, which may differ from our interpretation. Future tax legislative or regulatory changes in the United States, Mexico or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

***Our Mexican operations are subject to certain offshore regulatory and environmental laws and regulations promulgated by Mexico.***

Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the SENER, the CNH and other Mexican regulatory bodies. The laws and regulations governing activities in the Mexican energy sector have undergone significant reformation over the past decade, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. See Part I, Items 1 and 2. Business and Properties — Government Regulation — Regulation in Shallow Waters Off the Coast of Mexico and Part I, Items 1 and 2. Business and Properties — Government Regulation — Hydrocarbon Export Regulation in Mexico for additional disclosure relating to the legal requirements imposed by SENER, CNH or other Mexican regulatory bodies to which we may be subject in the pursuit of our operations.

In addition, our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the ASEA. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are also relatively new, having been significantly reformed in 2013 and 2014, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. See Part I, Items 1 and 2. Business and Properties — Environmental and Occupational Safety and Health Regulations — Environmental Regulation in Shallow Waters Off the Coast of Mexico for additional disclosure relating to the legal requirements imposed by ASEA or other Mexican regulatory bodies to which we may be subject in the pursuit of our operations. The permit holders must comply with requirements relating to insurance, facility construction and design, law compliance, and risk analysis scenarios.

Under the Block 7 PSC, we are also jointly and severally liable for the performance of all obligations under the PSC, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSC.

***Three-dimensional seismic interpretation does not guarantee that hydrocarbons are present or if present, produce in economic quantities.***

We rely on 3D seismic studies to assist us with assessing prospective drilling opportunities on our properties, as well as on properties that we may acquire. Such seismic studies are merely an interpretive tool and do not necessarily guarantee that hydrocarbons are present or, if present, produce in economic quantities, and seismic indications of hydrocarbon saturation are generally not reliable indicators of productive reservoir rock. These limitations of 3D seismic data may impact our drilling and operational results, and consequently our financial condition.

*We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act.*

We are subject to the U.S. Foreign Corrupt Practices Act (the "FCPA") and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We may do business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

Under the Block 7 PSC with the CNH, we work as a consortium with our partners. Violations of the FCPA, by any consortium partner, may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the CNH has the authority to rescind the PSC if these violations occur.

***Our operations are subject to various risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur and reduce demand for the crude oil and natural gas that we produce.***

Climate change continues to attract considerable public, political and scientific attention both domestically and abroad. For example, the IRA 2022 contains significant financial incentives for the development of renewable energy, alternative fuels, supporting infrastructure and carbon capture and sequestration and imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge generated from sources in the onshore petroleum and natural gas production categories. Beginning in 2024, the methane emissions charge is set at $900 per ton of methane, and is expected to increase to $1,200 in 2025, and $1,500 in 2026 and each year after. Such additional fees could significantly impact our operating costs. Further, the incentives offered for various clean energy industries could further accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives. These regulatory changes could ultimately decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently adversely affect our business.

Numerous other executive actions and legislative and regulatory initiatives have been enacted or may be anticipated, such as cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Further, regulations or legal actions are likely at the state, regional or international levels of government to monitor and limit existing GHG emissions as well as to restrict or eliminate such future emissions. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and GHG emissions. See Part I, Items 1 and 2. Business and Properties — Environmental and Occupational Safety and Health Regulations — Climate Change for additional disclosure relating to risks arising out of the threat of climate change.

The adoption of legislation or regulatory programs to reduce or eliminate future GHG emissions could require us to incur significant operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce or eliminate future GHG emissions could have an adverse effect on our business, financial condition and results of operations. Also, political, financial and litigation risks may result in our restricting or canceling production activities or impairing the ability to continue to operate in an economic manner. Further, if any such effects of climate changes were to occur, they could have an adverse effect on our financial condition and results of operations.

***Increasing attention to environmental, social and governance matters may impact our business.***

Increasing attention to climate change and societal expectations on companies to address climate change and substitute energy sources for fossil fuels may result in increased costs, reduced demand for our products and our services and the products and services of our customers, reduced profits, increased compliance measures, investigations and litigation, and negative impacts on our stock price and access to capital markets.

Moreover, while we endeavor to publish transparent sustainability reports, the voluntary disclosures therein are sometimes based on assumptions and calculations that may or may not be representative of actual or forecasted risks or events, including the costs associated therewith. Such assumptions and calculations are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many environmental, social and governance ("ESG") matters.

The Board's SSCR Committee is the primary committee responsible for overseeing and managing our ESG initiatives. Our Director of ESG is responsible for driving our sustainability initiatives, engaging with stakeholders, benchmarking our ESG data, and evaluating potential and emerging ESG drivers. We note, however, that our governance structure may not be able to adequately identify or manage ESG-related risks and opportunities, which may include failing to achieve our GHG emissions targets or other ESG-related aspirational goals, including but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such goals. Moreover, given the evolving nature of GHG emissions accounting methodologies and climate science, it is possible that factors outside of our control could give rise to the need to restate or revise our emissions intensity reduction goals, cause us to miss them altogether, or limit the impact of success of achieving our goals. Additionally, to the extent we meet such targets, they may be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that the offsets we do purchase will successfully achieve the emissions reductions they represent.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. We and other companies in our industry publish sustainability reports that are made available to investors. Such ratings and reports are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of investment to other industries which could have a negative impact on our stock price and/or our access to and costs of capital. Additionally, certain institutional lenders may decide not to provide funding to us based on ESG concerns, which could adversely affect our financial condition and access to capital for potential growth projects. To the extent ESG matters negatively impact our reputation, we may also be unable to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Furthermore, public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," (i.e., misleading information or false claims overstating potential ESG benefits). For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG statements, emission reduction claims, approaches to accounting for GHG emissions reductions, or other ESG-related goals or standards were misleading, false, or otherwise deceptive. As a result, we may face increased litigation risk from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further regulatory ESG-related focus and scrutiny.

***A change in the jurisdictional characterization of our FERC-jurisdictional pipelines, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of such asset, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.***

One of our subsidiaries owns an oil pipeline that extends from South Pass Block 89 in federal waters, offshore Louisiana, to the West Delta Receiving Station in Venice, Louisiana. This subsidiary has previously been granted a waiver of certain portions of the ICA and related regulations by the FERC. However, if the pipeline's circumstances change, the FERC could, either at the request of other entities or on its own initiative, assert that such pipeline no longer qualifies for a waiver. In the event that the FERC determines the pipeline no longer qualified for a waiver, we would likely be required to file a tariff with the FERC, provide a cost justification for the transportation charge and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on this pipeline could adversely affect our results of operations. Please also see Part I, Items 1 and 2 Business and Properties — Environmental and Occupational Safety and Health Regulations — Federal Regulation of Sales and Transportation of Crude Oil for more information.

***We are upgrading our accounting system to a more recent version and, if this upgraded version proves ineffective or we experience difficulties with the migration, we may be unable to timely or accurately prepare financial reports.***

We are in the process of upgrading our accounting systems. Any problems or delays associated with the implementation of our accounting platform or the failure to complete such implementation on a timely basis could adversely affect our ability to report financial information as our company grows, including the filing of our quarterly or annual reports with the SEC on a timely and accurate basis. After converting from prior systems and processes, we may discover data integrity problems or other issues that, if not corrected, could impact our business or financial results.

### Risks Related to our Capital Structure and Ownership of our Common Stock

***Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility, and the indentures governing our New Senior Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.***

The terms of the agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiaries to us;
- merging, consolidating or transferring all or substantially all of our assets;
- hedging future production; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, including the Bank Credit Facility, the indentures for each of Talos Production Inc.'s (the "Issuer") 9.000% Second-Priority Senior Secured Notes due 2029 (the "9.000% Notes") and 9.375% Second-Priority Senior Secured Notes due 2031 (the "9.375% Notes," and together, with the 9.000% Notes, our "New Senior Notes"), have important consequences on our operations, including:

- requiring that we dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures, and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates because debt under our Bank Credit Facility is at variable rates.

See Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Developments — Debt Offering for additional information on the issuance of the New Senior Notes.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Sustained low oil and natural gas prices have a material and adverse effect on our liquidity position. Our cash flow is highly dependent on the prices we receive for oil and natural gas.

We depend on our Bank Credit Facility for a portion of our future capital needs. We are required to comply with certain debt covenants and certain financial ratios under the Bank Credit Facility. Our borrowing base under the Bank Credit Facility, which is redetermined semi-annually, is based on an amount established by the lenders after their evaluation of our proved oil and natural gas reserve values. Such borrowing base determines the amount which is available under our Bank Credit Facility. If, due to a redetermination of our borrowing base, our outstanding borrowings plus outstanding letters of credit exceed our redetermined borrowing base (referred to as a borrowing base deficiency), we could be required to repay such borrowing base deficiency. Our Bank Credit Facility allows us to cure a borrowing base deficiency through any combination of the following actions: (i) repay amounts outstanding sufficient to cure the borrowing base deficiency within 30 days after the existence of such deficiency; (ii) add additional oil and gas properties acceptable to the banks to the borrowing base and take such actions necessary to grant the banks a mortgage in such oil and gas properties within 30 days after the existence of such deficiency; (iii) pay the deficiency in four equal monthly installments with the first installment due within 30 days after the existence of such deficiency or (iv) any combination of the above. We are required to elect one of the foregoing options within 10 days after the existence of such deficiency.

We may not have sufficient funds to make such repayments. If we do not repay our debt out of cash on hand, we could attempt to restructure or refinance such debt, reduce or delay investments and capital expenditures, sell assets, or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flows from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets are available to pay or refinance such debt. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of our debt, including our Bank Credit Facility and the respective indentures for our New Senior Notes, may also prohibit us from taking such actions. Factors that affect our ability to raise cash through offerings of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offerings, refinancing or sale of assets. We cannot assure you that any such offerings, restructuring, refinancing or sale of assets would be successfully completed.

***A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.***

We use our cash flows from operating activities and borrowings under our Bank Credit Facility to fund our capital expenditures, and we rely on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions. As such, we may not be able to access adequate funding under our Bank Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a borrowing base redetermination or a breach or default under our Bank Credit Facility, including a breach of a financial covenant or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations.

We may also face limitations on our ability to access the debt and equity capital markets and complete asset sales, increased counterparty credit risk on our derivatives contracts and requirements by our contractual counterparties to post collateral guaranteeing performance. Events involving limited liquidity, defaults, non-performance or other adverse developments that affect financial institutions, transactional counterparties or other companies in the financial services industry or the financial services industry generally, or concerns or rumors about any events of these kinds or other similar risks, have in the past and may in the future lead to market-wide liquidity problems. Most recently, on May 1, 2023, First Republic was closed by the California Department of Financial Protection and Innovation (“DFPI”), which appointed the FDIC as receiver. The FDIC sold First Republic’s deposits and most of its assets to JPMorgan Chase Bank, N.A. On March 10, 2023, Silicon Valley Bank (“SVB”) was closed by the DFPI, which appointed the FDIC as receiver. Similarly, on March 12, 2023, Signature Bank and Silvergate Capital Corp. were each swept into receivership. Although a statement by the Department of the Treasury, the Fed and the FDIC indicated that all depositors of SVB would have access to all of their money after only one business day of closure, including funds held in uninsured deposit accounts, borrowers under credit agreements, letters of credit and certain other financial instruments with SVB, Signature Bank or any other financial institution that is placed into receivership by the FDIC may be unable to access undrawn amounts thereunder. Access to funding sources and other credit arrangements could be significantly impaired by factors that affect the financial services industry or economy in general.

In addition, from time to time, we could be required to, or we or our affiliates may seek to, retire or purchase our outstanding debt through cash purchases and/or exchanges for equity or debt, open-market purchases, privately negotiated transactions or other transactions. Such debt repurchase or exchange transactions, if any, will be upon such terms and at such prices as we may determine and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. Such transactions may give rise to taxable cancellation of indebtedness income (to the extent the fair market value of the property exchanged, or the amount of cash paid to acquire the outstanding debt, is less than the adjusted issue price of the outstanding debt) and adversely impact our ability to deduct interest expenses in respect of our debt against our taxable income in the future. This could result in a current or future tax liability, which could adversely affect our financial condition and cash flows.

***We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.***

We spend a substantial amount of capital for the acquisition, exploration, exploitation, development, and production of oil and natural gas reserves. We fund our capital expenditures primarily through operating cash flows, cash on hand and borrowings under our Bank Credit Facility, if necessary. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment and regulatory, technological and competitive developments. A further reduction in commodity prices may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

- our proved reserves;
- the level of hydrocarbons we are able to produce from our wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Bank Credit Facility.

If low oil and natural gas prices, operating difficulties, declines in reserves or other factors, many of which are beyond our control, cause our revenues, cash flows from operating activities, and the borrowing base under our Bank Credit Facility to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditure program. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot be sure that additional debt or equity financing will be available, and we cannot be sure that cash flows provided by operations will be sufficient to meet these requirements. For example, the ability of oil and gas companies to access the equity and high yield debt markets has been, and continues to be, significantly limited.

***We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.***

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. We have no independent means of generating revenue. To the extent Talos Production Inc. has available cash, we will cause Talos Production Inc. to make distributions of cash to us, directly and indirectly through our wholly owned subsidiaries, to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock. As we have never declared or paid any cash dividends on our common stock, we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our Board of Directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions the agreements governing Talos Production Inc.'s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us. To the extent that we need funds and Talos Production Inc. is restricted from making such distributions under applicable law or regulation or under the terms of our financing agreements, or is otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt — Limitation on Restricted Payments Including Dividends* for additional information.

***Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our current and future financial position and results of operations.***

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the U.S. Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased or decreased costs. As a result, we may significantly increase or decrease our estimated asset retirement obligations in future periods. For example, because we operate in the U.S. Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated costs to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimates of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane or other natural disaster. Also, a sustained lower commodity price environment may cause our non-operator partners to be unable to pay their share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs.

We have divested, as assignor, various leases, wells and facilities located in the U.S. Gulf of Mexico where the purchasers, as assignees, typically assume all abandonment obligations acquired. Certain of these counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Under certain circumstances, regulations or federal laws such as the OCSLA could impose joint and several strict liability and require predecessor assignors, such as us, to assume such obligations. As of December 31, 2023, we have accrued \$3.3 million and \$12.3 million in obligations reflected as "Other current liabilities" and "Other long-term liabilities", respectively, on the Consolidated Balance Sheets. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* and Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies* for more information.

***We may not realize the anticipated benefits from our current and future acquisitions, and we may be unable to successfully integrate future acquisitions.***

Our growth strategy will, in part, rely on acquisitions. We have to plan and manage acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. We expect to grow in the future by expanding the exploitation and development of our existing assets, in addition to growing through targeted acquisitions in the U.S. Gulf of Mexico or in other basins. We may not realize all of the anticipated benefits from our future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, inexperience with operating in new geographic regions, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices. In particular, this risk arises in the context of the pending QuarterNorth Acquisition, which is expected to close in the first quarter of 2024.

In addition, integrating acquired businesses and properties involves a number of special risks and unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. These difficulties include, among other things:

- operating a larger organization;
- coordinating geographically disparate organizations, systems and facilities;
- integrating corporate, technological and administrative functions;
- diverting management's attention from regular business concerns;
- diverting financial resources away from existing operations;
- increasing our indebtedness; and
- incurring potential environmental or regulatory liabilities and title problems.

Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results. The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which decreases the time they have to manage our business. If our management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

***Our current and future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.***

We expect that future acquisitions will contribute to our growth. In connection with potential future acquisitions, we may only be able to perform limited due diligence.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities, including P&A liabilities. Such assessments are inexact and may not disclose all material issues or liabilities. In connection with our assessments, we perform a review of the acquired properties. However, such a review may not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

***Resolution of litigation could materially affect our financial position and results of operations.***

Resolution of litigation could materially affect our financial position and results of operations. To the extent that potential exposure to liability is not covered by insurance or insurance coverage is inadequate, we may incur losses that could be material to our financial position or results of operations in future periods.

***The corporate opportunity provisions in our Second Amended and Restated Certificate of Incorporation could enable others to benefit from corporate opportunities that might not otherwise be available to us.***

Subject to the limitations of applicable law, our Second Amended and Restated Certificate of Incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits our officers or directors who are also officers, directors, employees, managing directors, or other affiliate of a Principal Stockholder (as defined in the Second Amended and Restated Certificate of Incorporation) to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any of our officers or directors who is also an officer, director, employee, managing director or other affiliate of the Principal Stockholders becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as an director or officer of us), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to any other entity or individual and that director or officer will not be deemed to have acted in a manner inconsistent with his or her fiduciary duty to us or our stockholders.

Any of our directors may vote upon any contract or any other transaction between us and any affiliated corporation without regard to the fact that such person is also a director or officer of such affiliated corporation.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of others.

***Our Second Amended and Restated Certificate of Incorporation designates the Court of Chancery of the State of Delaware and, to the extent enforceable, the federal district courts of the United States of America as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.***

Our Second Amended and Restated Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (i) any derivative action or proceeding brought on our or our stockholders' behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our current or former directors, officers, employees, agents and stockholders to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL, our Second Amended and Restated Certificate of Incorporation or our Second Amended and Restated Bylaws, (iv) any action as to which the DGCL confers jurisdiction to the Court of Chancery of the State of Delaware, or (v) any other action asserting a claim that is governed by the internal affairs doctrine shall be the Court of Chancery of the State of Delaware. Our Second Amended and Restated Certificate of Incorporation also provides that, to the fullest extent permitted by applicable law, the federal district courts of the U.S. are the exclusive forum for resolving any complaint asserting a cause of action arising under the Securities Act, subject to and contingent upon a final adjudication in the State of Delaware of the enforceability of such exclusive forum provision. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts with respect to suits brought to enforce a duty or liability created by the Securities Act or the rules and regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain claims under the Securities Act.

Notwithstanding the foregoing, the exclusive forum provision does not apply to suits brought to enforce any liability or duty created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring an interest in any shares of our capital stock shall be deemed to have notice of and to have consented to the forum provisions in our Second Amended and Restated Certificate of Incorporation.

These choice-of-forum provisions may limit a stockholder's ability to bring a claim in a judicial forum that he, she or it believes to be favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits. Alternatively, if a court were to find these provisions of our Second Amended and Restated Certificate of Incorporation inapplicable or unenforceable with respect to one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could materially adversely affect our business, financial condition and results of operations and result in a diversion of the time and resources of our management and board of directors.

While the Delaware courts have determined that choice of forum provisions of this type are facially valid, uncertainty exists as to whether a court would enforce such provision, and as such, a stockholder may nevertheless seek to bring a claim in a venue other than those designated in our exclusive forum provision. In such instance, to the extent applicable, we would expect to vigorously assert the validity and enforceability of our exclusive forum provision. This may require additional costs associated with resolving such action in other jurisdictions and there can be no assurance that the provisions will be enforced by a court in those other jurisdictions.

***Future sales, or the perception of future sales, by us or our existing stockholders in the public market could cause the market price for our common stock to decline.***

The sale of substantial amounts of shares of our common stock in the public market, or the perception that such sales could occur, could harm the prevailing market price of shares of our common stock. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate.

Certain holders of our common stock, including certain former stockholders of EnVen, are entitled to rights with respect to registration of approximately 17.9 million shares of our common stock (representing approximately 11.3% of the outstanding shares of our common stock as of February 21, 2024) under the Securities Act pursuant to certain registration rights agreements. In addition, we intend to enter into a registration rights agreement in connection with the QuarterNorth Acquisition, which will become effective at the closing, which will grant registration rights to approximately 24.8 million shares of our common stock (representing approximately 13.5% of the outstanding shares of our common stock immediately following the closing of the acquisition. If these holders of our common stock, by exercising their registration rights, sell a large number of shares, the market price for our common stock could be adversely affected.

***The interests of the Slim Family and its affiliates may differ from the interests of our other stockholders.***

As of February 21, 2024, an entity controlled by the Carlos Slim Helu and his family members (collectively, the "Slim Family") beneficially owned and possessed voting power approximately 21.9% of our common stock.

The Slim Family has significant influence over matters submitted to stockholders for approval, including changes in capital structure, transactions requiring stockholder approval under Delaware law, and corporate governance. The Slim Family may have different interests than other holders of our common stock and may make decisions adverse to your interests.

Among other things, the Slim Family's concentration of voting power could delay or defer a sale of us that many of our other stockholders support. This concentration of voting power could discourage a potential investor from seeking to acquire our common stock and, as a result, might harm the market price of our common stock.

**Risks Related to the QuarterNorth Acquisition and our Integration of QuarterNorth Into our Business**

***The market price for our common stock following the closing of the QuarterNorth Acquisition may be affected by factors different from those that historically have affected or currently affect our common stock.***

Our financial position may differ from our financial position before the completion of the QuarterNorth Acquisition, and the results of operations of the combined company may be affected by some factors that are different from those currently affecting our results of operations. Accordingly, the market price and performance of our common stock is likely to be different from the performance of our common stock in the absence of the QuarterNorth Acquisition. In addition, general fluctuations in stock markets could have a material adverse effect on the market for, or liquidity of, our common stock, regardless of our actual operating performance.

***Our stockholders, as of immediately prior to the QuarterNorth Acquisition, will have reduced ownership in the combined company after closing of the transaction.***

Based on the number of shares of common stock outstanding immediately following the closing of the QuarterNorth Acquisition, our existing stockholders would own approximately 86.5% of the outstanding shares of the combined company and QuarterNorth's existing members would own approximately 13.5% of the outstanding shares of the combined company. As a result, our current stockholders will have less influence on the policies of the combined company than they currently have following the closing of the QuarterNorth Acquisition.

***We may not consummate the QuarterNorth Acquisition on the terms currently contemplated or at all.***

We may not consummate the QuarterNorth Acquisition, which is subject to the satisfaction of customary closing conditions. Many of the conditions to completion of the QuarterNorth Acquisition are not within either our or QuarterNorth's control, and neither we nor QuarterNorth can predict when, or if, these conditions will be satisfied. If any of these conditions are not satisfied or waived prior to the outside date, it is possible that the QuarterNorth Acquisition may be terminated. Although we have agreed with QuarterNorth to use reasonable best efforts, subject to certain limitations, to promptly complete the QuarterNorth Acquisition, these and other conditions to the completion of the QuarterNorth Acquisition may fail to be satisfied. In addition, satisfying the conditions to and completion of the QuarterNorth Acquisition may take longer, and could cost more, and require additional borrowings, than we currently expect. There can be no assurance that such conditions will be satisfied or that the QuarterNorth Acquisition will be consummated on the terms currently contemplated or at all. If additional borrowings are required to consummate the QuarterNorth Acquisition, our total debt and leverage will be greater than currently anticipated, and our availability under our Bank Credit Facility will be reduced by a corresponding amount. If we fail to complete the QuarterNorth Acquisition, our management will have broad discretion in the use of proceeds from the January Equity Offering (as defined herein), and may use such proceeds in ways in which you do not approve.

***Failure to complete the QuarterNorth Acquisition could negatively impact our stock price and have a material adverse effect on our results of operations, cash flows and financial position.***

If the QuarterNorth Acquisition is not completed for any reason, including as a result of failure to obtain all requisite regulatory approvals, we may be materially adversely affected and, without realizing any of the benefits of having completed the acquisition, we would be subject to a number of risks, including the following:

- we may experience negative reactions from the financial markets, including negative impacts on our stock price;
- we may experience negative reactions from our customers, distributors, suppliers, vendors, landlords, joint venture partners and other business partners;
- we will still be required to pay certain significant costs relating to the acquisition, such as legal, accounting, financial advisor and printing fees;
- QuarterNorth may be entitled to receive the full amount of the deposit pursuant to the Agreement and Plan of Merger, dated as of January 13, 2024, by and among the Company, QuarterNorth, Compass Star Merger Sub Inc. and the Equityholder Representatives named therein (the "QuarterNorth Merger Agreement");
- the QuarterNorth Merger Agreement places certain restrictions on our conduct pursuant to the terms thereof, which may delay or prevent us from undertaking business opportunities that, absent the QuarterNorth Merger Agreement, may have been pursued;

- matters relating to the acquisition (including integration planning) require substantial commitments of time and resources by our management, which may have resulted in the distraction of our management from ongoing business operations and pursuing other opportunities that could have been beneficial to us; and
- litigation related to any failure to complete the acquisition or related to any enforcement proceeding commenced against us to perform our obligations pursuant to the QuarterNorth Merger Agreement.

If the QuarterNorth Acquisition is not completed, the risks described above may materialize and they may have a material adverse effect on our results of operations, cash flows, financial position and stock price.

***Future sales or issuances of our common stock could have a negative impact on our common stock price.***

If holders of our common stock, by exercising registration rights or otherwise, sell a large number of shares, the market price for our common stock could be adversely affected. It is possible that some QuarterNorth shareholders will decide to sell some or all of the shares of our common stock that they received as consideration in the QuarterNorth Acquisition. Shortly after the closing of the QuarterNorth Acquisition, we are obligated to file a registration statement covering the resale of potentially all of the shares issued to the QuarterNorth shareholders. In addition, in connection with the closing of the QuarterNorth Acquisition, we will enter into a registration rights agreement with certain QuarterNorth shareholders, pursuant to which we will grant such holders certain demand, "piggy-back" registration rights with respect to shares of our common stock received by such holders in the acquisition, subject to a lock-up period of 60 days following the closing.

Following the closing of the QuarterNorth Acquisition, the QuarterNorth shareholders will collectively own 24.8 million shares of our common stock, representing approximately 13.5% of the outstanding shares of our common stock after the closing of that acquisition. We expect that at least a majority of those shares will be subject to the lock-up period.

Any disposition by a significant stockholder of our common stock, including by one of the RRA Holders, or the perception in the market that such dispositions could occur, may cause the price of our common stock to fall. Any such decline could impair the combined company's ability to raise capital through future sales of our common stock. Further, our common stock may not qualify for investment indices and any such failure may discourage new investors from investing in our common stock.

***Our and QuarterNorth's business relationships may be subject to disruption due to uncertainty associated with the QuarterNorth Acquisition, which could have a material adverse effect on the results of operations, cash flows and financial position of us pending and following the closing of the QuarterNorth Acquisition.***

Parties with which we or QuarterNorth do business may experience uncertainty associated with the QuarterNorth Acquisition, including with respect to current or future business relationships with us following the closing of the QuarterNorth Acquisition. Our and QuarterNorth's business relationship may be subject to disruption as customers, distributors, suppliers, vendors, landlords, joint venture partners and other business partners may attempt to delay or defer entering into new business relationships, negotiate changes in existing business relationships or consider entering into business relationships with parties other than us or QuarterNorth following the QuarterNorth Acquisition. These disruptions could have a material and adverse effect on the results of operations, cash flows and financial position of us, regardless of whether the QuarterNorth Acquisition is completed, as well as a material and adverse effect on our ability to realize the expected benefits of the QuarterNorth Acquisition.

***The QuarterNorth Merger Agreement subjects us to restrictions on our business activities prior to the Effective Time.***

The QuarterNorth Merger Agreement subjects us to restrictions on our business activities prior to the closing of the QuarterNorth Acquisition (the "Effective Time"). The QuarterNorth Merger Agreement obligates each of us and QuarterNorth to generally conduct our businesses in the ordinary course until the Effective Time and to use commercially reasonable efforts to preserve intact our present business organizations. Additionally, the QuarterNorth Merger Agreement restricts us and QuarterNorth from certain other actions prior to the Effective Time, including, among other things, (i) amending our respective organizational documents, (ii) issuing, selling, pledging, disposing of or encumbering any of our respective securities and (iii) merging, consolidating, combining or amalgamating with any person or acquiring any assets or incurring indebtedness in excess of certain monetary thresholds.

These restrictions could prevent us from pursuing certain business opportunities that arise prior to the Effective Time.

***The failure to successfully integrate our business and operations with QuarterNorth in the expected time frame may adversely affect our future results.***

The integration process of our business with those of QuarterNorth could result in the loss of key employees, customers, providers, vendors or business partners, the disruption of each company's or all companies' ongoing businesses, inconsistencies in standards, controls, procedures and policies, potential unknown liabilities and unforeseen expenses, delays, or regulatory conditions or higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated. Specifically, the following issues, among others, must be addressed in integrating the operations in order to realize the anticipated benefits of the QuarterNorth Acquisition:

- combining the companies' operations and corporate functions and the resulting difficulties associated with managing a larger, more complex, integrated business;
- combining our business with QuarterNorth in a manner that permits the combined company to achieve any cost savings or operating synergies anticipated to result from the QuarterNorth Acquisition;
- reducing the additional and unforeseen expenses such that integration costs are not more than anticipated;
- minimizing the loss of key employees;
- identifying and eliminating redundant functions and assets;
- maintaining existing agreements with customers, providers and vendors or business partners and avoiding delays in entering into new agreements with prospective customers, providers and vendors or business partners; and
- consolidating the companies' operating, administrative and information technology infrastructure.

In addition, at times the attention of certain members of our management and resources may be focused on the integration of the businesses of the companies and diverted from day-to-day business operations or other opportunities that may have been beneficial to us, which may disrupt our ongoing business.

## Item 1B. Unresolved Staff Comments

None.

## Item 1C. Cybersecurity

***Assessing, Identifying and Managing Cybersecurity Risks*** **—** We strive to align our cybersecurity operating model with the National Institute of Standards and Technology ("NIST") Cybersecurity Framework to enhance our ability to protect, detect, respond, and recover from potential cybersecurity threats. Our cybersecurity team actively works to assess, identify and manage risks in our information systems in order to protect the confidentiality, integrity and availability of our digital infrastructure. The cybersecurity team meets regularly to evaluate potential threats, discuss best practices and identify new solutions to help mitigate cyber risks.

We engage third-party service providers to conduct evaluations of our cybersecurity controls through penetration testing, independent audits and consulting on best practices to address existing and new challenges. These evaluations include testing the design and operational effectiveness of our cybersecurity controls. To further enhance the capabilities of our internal systems, we utilize third-party vendors to provide extended coverage of our information technology and operational technology environments. We also share and receive threat intelligence with companies in the energy sector, government agencies, information sharing and analysis centers and cybersecurity associations in order to monitor and address developments in the cybersecurity environment.

To serve as an additional protection from outside threats, we also seek to prepare our employees and contractors about cybersecurity risks through training, simulated phishing exercises and awareness campaigns. We have implemented software and processes to help identify and evaluate risks from cybersecurity threats associated with third-party service vendors. In the event of a cybersecurity incident deemed to have a moderate or higher business impact, we have an incident response plan to notify senior leadership and to address how to contain the incident, mitigate the impact, and restore normal operations efficiently.

***Cybersecurity Risk Assessment*** **—** We have integrated cybersecurity risk management into our broader Enterprise Risk Management ("ERM") framework to promote a company-wide culture of cybersecurity risk management. Our ERM framework is designed to identify and prioritize company-wide risks, including cybersecurity threats, and integrate mitigation measures into our business, operational and capital structure planning activities. The purpose of the ERM framework is to enable the Board and executive leadership to (1) align risk management with strategic objectives, (2) identify risks, including cybersecurity risks, throughout the organization, (3) assess and prioritize risks that could impact the Company's operational and strategic objectives, (4) develop and monitor risk mitigation initiatives, and (5) report and assess material risks, mitigation strategies and progress to the Board and/or its applicable committees. Cybersecurity risk is reviewed by a cross-functional, management-level ERM Steering Committee as part of the Company's overall enterprise risk management program.

***Board of Directors' Oversight of Risks from Cybersecurity Threats —*** The Board of Directors is aware of the importance of managing risks associated with cybersecurity threats. The Audit Committee has been delegated responsibility by the Board for overseeing the Company's overall enterprise risk management program, including cybersecurity risk. The Audit Committee receives reports at least quarterly from the Director of Information Technology regarding cybersecurity matters, which may include, among other things, the results of cybersecurity audits, cybersecurity maturity assessments, other information technology matters, risk mitigation strategies, data protection and progress on initiatives. The Audit Committee Chair is responsible for reporting key cybersecurity issues regarding current and potential material cybersecurity threats and our risk mitigation response strategies to the Board. To further inform our Board and management on emerging cybersecurity issues, we periodically engage third-party cybersecurity experts to report to the Audit Committee, other directors, and management, as applicable, on topics that may include, among other things, the latest cybersecurity trends, new technologies, evolving threats in the marketplace, proposed initiatives, legislation, and reporting standards.

***Management's Role in Assessing and Managing Cybersecurity Threats —*** Our information technology team is responsible for assessing, identifying and managing cybersecurity risks. Top cybersecurity risks are also integrated into our overall ERM framework and overseen at the management level by the ERM Steering Committee. Our Director of Information Technology, who reports directly to the Chief Financial Officer ("CFO") and Senior Vice President and is a member of the ERM Steering Committee, is responsible for our efforts to comply with applicable cybersecurity standards, establish cybersecurity protocols and protect the integrity, confidentiality and availability of our information technology infrastructure. Technology and cybersecurity policy decisions are made by our Director of Information Technology in consultation with our CFO and Senior Vice President. In addition, our Director of Information Technology has a direct line of communication with our President and CEO and Executive Vice President and General Counsel as needed. Our Director of Information Technology has over 20 years of experience in cybersecurity, holds a Master of Science in Cybersecurity from the University of Houston and is a Certified Information Systems Security Professional and a Boardroom Certified Qualified Technology Expert.

***Impact of Risks from Cybersecurity Threats —*** As of the date of this Annual Report, we are not aware of previous cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, although the Company regularly experiences cybersecurity incidents that are not deemed material to our operations. Examples of cybersecurity threats we face include incidents common to most companies in the energy industry, such as phishing, business email compromise, ransomware and denial-of-service, as well as attacks from more advanced sources, including nation state actors, that target companies in the energy industry. Our customers, suppliers, subcontractors and joint venture partners face similar cybersecurity threats, and a cybersecurity incident impacting us or any of these entities could materially adversely disrupt our operations, including our drilling operations, and affect our performance and results of operations. We acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents remains. Please see Part I, Item 1A. "Risk Factors — Risks Related to our Business and the Oil and Natural Gas Industry — Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions."

**Item 3. Legal Proceedings**

We are named as a party in certain lawsuits and regulatory proceedings arising in the ordinary course of business. We do not expect that these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

In June 2019, David M. Dunwoody, Jr., former President of EnVen, filed a lawsuit against EnVen in Texas District Court alleging that the circumstances of his resignation entitled him to the severance payments and benefits under his employment agreement dated as of November 6, 2015 as a resignation for "Good Reason." In September 2021, the trial court entered a judgment in favor of Mr. Dunwoody, inclusive of Mr. Dunwoody's legal fees and interest. EnVen filed a Notice of Appeal in December 2021. In April 2023, the appellate court affirmed the trial court's judgment. The Company filed a petition for review with the Texas Supreme Court on August 2, 2023, which was denied on January 26, 2024. As of December 31, 2023, the Company has recorded $14.3 million as "Other current liabilities" on the Condensed Consolidated Balance Sheets related to the litigation.

On November 11, 2013, two lawsuits were filed, and on November 12, 2013, a third lawsuit was filed, against Stone Energy Corporation ("Stone") and other named co-defendants, by the Parish of Jefferson ("Jefferson Parish"), on behalf of Jefferson Parish and the State of Louisiana, in the 24th Judicial District Court for the Parish of Jefferson, State of Louisiana, alleging violations of the State and Local Coastal Resources Management Act of 1978, as amended, and the applicable regulations, rules, orders and ordinances thereunder (collectively, the "CRMA"), relating to certain of the defendants' alleged oil and gas operations in Jefferson Parish, and seeking to recover alleged unspecified damages to the Jefferson Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Jefferson Parish Coastal Zone and related costs and attorney's fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the three lawsuits. In connection with Stone's filing of bankruptcy in December 2016, Jefferson Parish dismissed its claims against Stone in these three lawsuits without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. In 2018, the Jefferson Parish lawsuits were removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs moved to remand the lawsuit to the state courts. Plaintiffs' motions to remand were submitted to the state court for decision in two of the lawsuits on February 15, 2023. Plaintiffs filed motions to remand, which the District Court granted, remanding the lawsuits back to the 24th Judicial District Court for the Parish of Jefferson. Defendants who removed the Jefferson Parish lawsuits have filed notices of appeal providing notice that they intend to appeal the District Court's orders granting Plaintiffs' motion to remand.

On November 8, 2013, a lawsuit was filed against Stone and other named co-defendants by the Parish of Plaquemines ("Plaquemines Parish"), on behalf of Plaquemines Parish and the State of Louisiana, in the 25th Judicial District Court for the Parish of Plaquemines, State of Louisiana, alleging violations of the CRMA, relating to certain of the defendants' alleged oil and gas operations in Plaquemines Parish, and seeking to recover alleged unspecified damages to the Plaquemines Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Plaquemines Parish Coastal Zone, and related costs and attorney's fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the lawsuit. In connection with Stone's filing of bankruptcy in December 2016, Plaquemines Parish dismissed its claims against Stone without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. In state court, the Plaquemines Parish lawsuit was stayed pending the conclusion of trials in five other cases, also filed in Plaquemines Parish and alleging violations of the CRMA, but not involving Stone. However, in 2018, the Plaquemines Parish lawsuit was removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs have moved to remand the lawsuit to the state courts, but the case was administratively closed in federal court pending the appeal of another case, also filed in Plaquemines Parish and alleging violations of the CRMA, but not involving Stone. That appeal was resolved by the United States Court of Appeals for the Fifth Circuit on December 15, 2022, and on December, 22, 2022, plaintiffs filed a motion in federal court to re-open the lawsuit. The United States Court of Appeals for the Fifth Circuit has not yet ruled on the plaintiffs' motion to re-open. Plaintiffs filed motions to remand, which the District Court granted. However, the District Court also granted Defendants' motion to stay the remand order pending appeal. That appeal is currently pending before the United States Court of Appeals for the Fifth Circuit.

Legal proceedings are subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation. Accordingly, we cannot currently predict the manner and timing of the resolution of some of these matters and may be unable to estimate a range of possible losses or any minimum loss from such matters. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies* for more information.

**Item 4. Mine Safety Disclosures**

Not applicable.

## PART II

### Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuers Purchases of Equity Securities

#### Market for Common Stock

Our common stock is listed on the NYSE under the symbol “TALO”.

#### Holders of Record

Pursuant to the records of our transfer agent, as of February 21, 2024, there were approximately 180 holders of record of our common stock.

#### Dividends

We have never declared or paid any cash dividends on our common stock, and we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our Board of Directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions that the agreements governing Talos Production Inc.’s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt — Limitation on Restricted Payments Including Dividends* for additional information.

#### Securities Authorized for Issuance Under Equity Compensation Plans

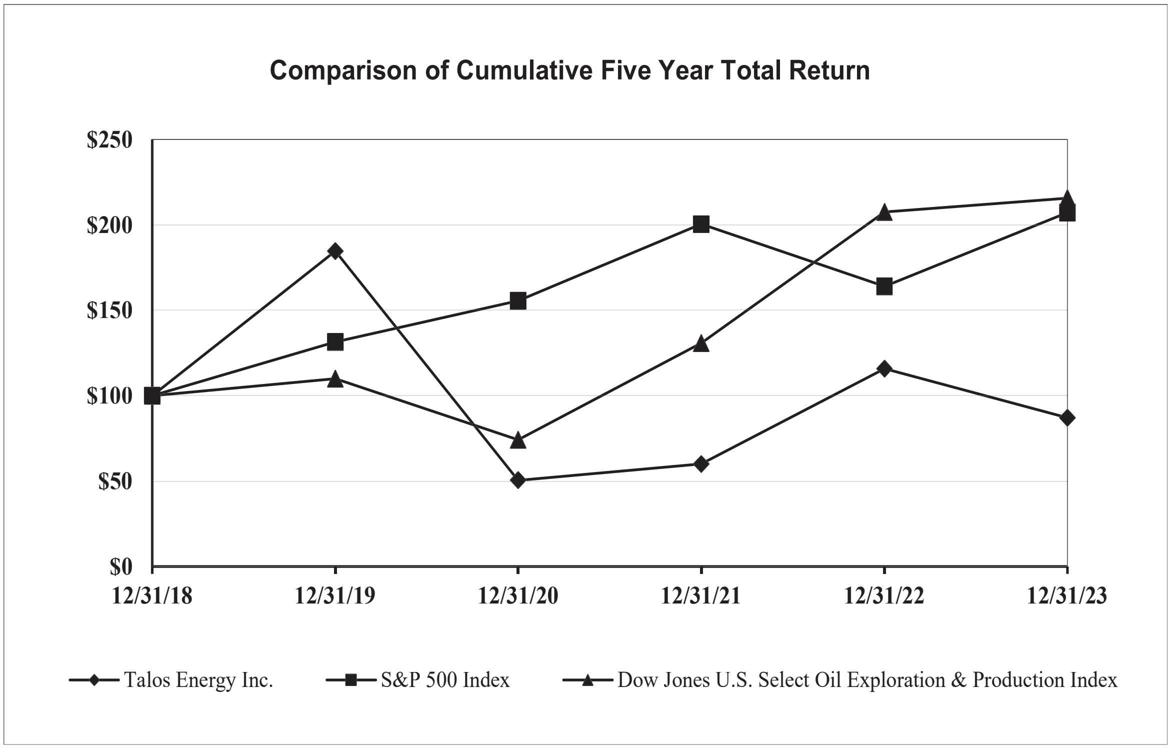
See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding securities authorized for issuance under equity compensation plans.

#### Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Our Board of Directors authorized a stock repurchase program on March 20, 2023 with an approved limit of $100.0 million and no set term limits. Repurchases may be made from time to time in the open market, in a privately negotiated transaction, or by such other means as will comply with applicable state and federal securities laws. The timing of any repurchases under the share repurchase program will depend on market conditions, contractual limitations and other considerations. The program may be extended, modified, suspended or discontinued at any time, and does not obligate the Company to repurchase any dollar amount or number of shares. There were no shares of common stock repurchased during the three months ended December 31, 2023. As of December 31, 2023, there is $52.5 million remaining under the authorized program.

**Stockholder Return Performance Presentation**

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of our common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for December 31, 2018 through December 31, 2023. The graph assumes that $100 was invested in our common stock and each index on December 31, 2018 and that dividends were reinvested.




| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| Talos Energy Inc. | $ 100 | $ 185 | $ 50 | $ 60 | $ 116 | $ 87 |
| S&P 500 Index | $ 100 | $ 131 | $ 156 | $ 200 | $ 164 | $ 207 |
| Dow Jones U.S. Exploration & Production Index | $ 100 | $ 110 | $ 74 | $ 131 | $ 208 | $ 216 |

The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

**Item 6. [Reserved]**

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

The following discussion and analysis of our financial condition and results of operations is based on, and should be read in conjunction with our Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15. Exhibits and Financial Statement Schedules; Part I, Items 1 and 2. Business and Properties; Part I, Item 1A. Risk Factors; and Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk. This discussion and analysis contains forward-looking statements that involve risk and uncertainties. Actual results may differ materially from those anticipated in these forward-looking statements.

This section of this Annual Report generally discusses 2023 and 2022 items and year-to-year comparisons between 2023 and 2022. Discussions of 2021 items and year-to-year comparisons between 2022 and 2021 that are not included in this Annual Report can be found in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of the Company's Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC.

### Our Business

We are a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through our operations, currently in the U.S. and offshore Mexico both through Upstream and the development of low carbon solutions opportunities. We leverage decades of technical and offshore operational expertise in the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. We are also utilizing our expertise to develop CCS projects to help reduce industrial emissions along the coast of the U.S. Gulf of Mexico.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic and geophysical databases, extensive infrastructure and an attractive and robust asset acquisition market. Additionally, we have access to state-of-the-art three-dimensional seismic data, some of which is aided by new and enhanced reprocessing techniques that have not been previously applied to our current acreage position. We use our broad regional seismic database and our reprocessing efforts to generate a large and expanding inventory of high-quality prospects, which we believe greatly improves our development and exploration success. The application of our extensive seismic database, coupled with our ability to effectively reprocess this seismic data, allows us to both optimize our organic drilling program and better evaluate a wide range of business development opportunities, including acquisitions and collaborative arrangement opportunities, among others.

### Outlook

We operate within an industry sector directly impacted by the energy transition. The energy transition will require both significant new investments in low-carbon energies and continued use of traditional hydrocarbons to meet the expected energy demand of an expanding global economy.

Our historical focus in the Gulf of Mexico results in an asset profile that differentiates us from the typical shale-driven onshore exploration and production companies. We are continuing to build operational scale. We expect that the QuarterNorth Acquisition, discussed below, will add scale to our business both in terms of production and operated infrastructure, while also diversifying our production across a broader asset base. While we are currently a pure play Gulf of Mexico company, diversification outside of our existing operational areas is always a possibility.

Oil and gas prices are expected to remain relatively stable in 2024. However, geopolitical tensions may contribute to hydrocarbon price volatility. For now, it looks like inflation will return to normal without a recession. Future changes to the benchmark interest rate remain uncertain. However, a modest reduction to the benchmark interest rate is the most likely scenario for 2024. We expect to scale back planned capital expenditures in 2024 compared to 2023. We remain exposed to increasing regulatory scrutiny and potential operational disruptions from weather-related events in the Gulf of Mexico. The limited scope of BOEM's 2024-2029 offshore oil and gas leasing program is disappointing to offshore producers. However, we have the ability to increase our acreage inventory through exchanges and mergers and acquisitions.

### Significant Developments

The following encompasses significant developments since the filing of our Annual Report on Form 10-K for the year ended December 31, 2022:

***QuarterNorth Acquisition*** **—** On January 13, 2024, we executed the QuarterNorth Merger Agreement to acquire QuarterNorth, a privately-held U.S Gulf of Mexico exploration and production company. The QuarterNorth Acquisition is expected to close during the first quarter of 2024. Consideration for the QuarterNorth Acquisition consists of (i) approximately $964.9 million in cash, (ii) the amount of net unrestricted cash of QuarterNorth as of December 31, 2023 and (iii) 24.8 million shares of the Company's common stock.

***Equity Offering* —** On January 22, 2024, we closed an upsized firm commitment underwritten public offering (the "January Equity Offering") of 34,500,000 shares of our common stock, resulting in net proceeds to us of approximately $388.5 million, after deducting underwriting discounts and commissions and before estimated offering expenses. We intend to use the net proceeds from the January Equity Offering to fund a portion of the cash consideration for the QuarterNorth Acquisition. However, the QuarterNorth Acquisition remains subject to certain conditions to closing. Pending the use of the proceeds of the January Equity Offering as described above, we may temporarily use all or a portion of such proceeds to reduce the borrowings outstanding under our Bank Credit Facility. In the event that the QuarterNorth Acquisition is not completed, the proceeds from the January Equity Offering will be used for general corporate purposes.

***Debt Offering* —** On February 7, 2024, Talos Production, Inc. issued in an upsized offering (the "Debt Offering") $1,250.0 million in aggregate principal amount of second-priority senior secured notes, consisting of $625.0 million aggregate principal amount of 9.000% second-priority senior secured notes due 2029 (the "9.000% Notes") and $625.0 million aggregate principal amount of 9.375% second-priority senior secured notes due 2031 (the "9.375% Notes" and, together with the 9.000% Notes, the "New Senior Notes"), in a private offering to eligible purchasers that is exempt from registration under the Securities Act. The New Senior Notes were issued pursuant to an indenture governing the 9.000% Notes (the "9.000% Notes Indenture") and an indenture governing the 9.375% Notes (the "9.375% Notes Indenture" and, together with the 9.000% Notes Indenture, the "Indentures"), each dated as of February 7, 2024 and by and among the Company, Talos Production Inc., the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. The New Senior Notes rank equally in right of payment with all existing and future senior obligations of the issuer and the guarantors thereto. The issuance of the New Senior Notes on February 7, 2024, resulted in $1,250.0 million gross proceeds. The net proceeds from the Debt Offering (i) are expected to fund a portion of the cash consideration for the pending QuarterNorth Acquisition as discussed above, (ii) funded the redemption (the "Redemptions") of all of the outstanding 11.75% Notes (defined below) and 12.00% Notes (defined below) (the "Senior Notes"), and (iii) paid premiums, fees and expenses related to the Redemptions and the issuance of the New Senior Notes. We intend to use any remaining net proceeds for general corporate purposes, which may include the repayment of a portion of the outstanding borrowings under the Bank Credit Facility.

An aggregate of $340 million principal amount of the New Senior Notes will be subject to a "special mandatory redemption" in the event that the transactions contemplated by the QuarterNorth Merger Agreement are not consummated on or before May 31, 2024 (or up to September 30, 2024 solely in the event the parties require additional time to satisfy certain requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, pursuant to the terms of the QuarterNorth Merger Agreement), or if we notify the trustee of the New Senior Notes that we will not pursue the consummation of the QuarterNorth Acquisition.

***Mexico Divestiture* —** On September 27, 2023, we sold a 49.9% interest in Talos Energy Mexico 7, S. de R.L. de C.V., a wholly owned subsidiary of the Company, to Zamajal, S.A. de C.V., a wholly owned subsidiary of Grupo Carso (the "Mexico Divestiture"). See Part IV, Item 15. Exhibits and Financial Statement Schedules **—** Note 3 — *Acquisitions and Divestitures* for additional information.

***Common Stock Repurchase Program* —** On March 20, 2023, we announced that our Board of Directors approved a $100.0 million common stock repurchase program. As of December 31, 2023, we have repurchased 3.4 million shares for a total of $47.5 million resulting in $52.5 million remaining under the authorized program. All repurchased shares are held in treasury.

**Factors Affecting the Comparability of our Financial Condition and Results of Operations**

The following items affect the comparability of our financial condition and results of operations for periods presented herein and could potentially continue to affect our future financial condition and results of operations.

***EnVen Acquisition* —** On February 13, 2023, we acquired EnVen Energy Corporation ("EnVen"), a private operator in the Deepwater U.S. Gulf of Mexico (the "EnVen Acquisition"). See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***Planned Downtime* —** We are vulnerable to downtime events impacting the transportation, gathering and processing of production. We produce the Phoenix Field through the HP-I that is operated by Helix. Helix is required to disconnect and dry-dock the HP-I every two to three years for inspection as required by the U.S. Coast Guard, during which time we are unable to produce the Phoenix Field.

During the year ended December 31, 2022, Helix dry-docked the HP-I. After conducting sea trials, production resumed in mid-September, resulting in a total shut-in period of 41 days. The shut-in resulted in an estimated deferred production of approximately 1.6 MBoepd for the year ended December 31, 2022, based on production rates prior to the shut-in. The next dry-dock is scheduled for the first half of 2024 with a projected shut-in period of approximately 55 days.

During the year ended December 31, 2022, we experienced approximately 26 days of planned third-party downtime due to maintenance of the Shell Odyssey Pipeline, which carries our production primarily from our Ram Powell Field, Main Pass 288 Field and non-operated Delta House facility. Production resumed in October 2022. We estimate the shut-in resulted in deferred production of approximately 0.7 MBoepd for the year ended December 31, 2022, based on production rates prior to the shut-in.

***Eugene Island Pipeline System*** — During the first quarter of 2022, we experienced approximately 40 days of unplanned third-party downtime due to maintenance of the Eugene Island Pipeline System, which carries our production from the Phoenix Field and Green Canyon 18 Field. For the year ended December 31, 2022, we estimate the shut-in has resulted in deferred production of approximately 1.2 MBoepd based on production rates prior to the shut-in.

**Known Trends and Uncertainties**

***Volatility in Oil, Natural Gas and NGL Prices —*** Historically, the markets for oil and natural gas have been volatile. Oil, natural gas and NGL prices are subject to wide fluctuations in supply and demand. Our revenue, profitability, access to capital and future rate of growth depends upon the price we receive for our sales of oil, natural gas and NGL production.

During January 1, 2023 through December 31, 2023, the daily spot prices for NYMEX WTI crude oil ranged from a high of \$93.67 per Bbl to a low of \$66.61 per Bbl and the daily spot prices for NYMEX Henry Hub natural gas ranged from a high of \$3.78 per MMBtu to a low of \$1.74 per MMBtu. Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of production. We hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for more additional information regarding our commodity derivative positions as of December 31, 2023.

The U.S. Energy Information Administration ("EIA") published its February 2024 Short-Term Energy Outlook on February 6, 2024. The EIA expects natural gas prices to average \$2.65 per MMBtu in 2024, and rise to an average of \$2.94 per MMBtu in 2025, up from an average of \$2.54 per MMBtu in 2023. Prices are expected to increase because of slowing growth in natural gas production and increasing U.S. liquefied natural gas exports, particularly in 2025 following the addition of new export capacity in late 2024. However, the EIA expects upward price pressures to be limited by relatively flat consumption of natural gas in the electric power sector and persistently high inventories. The EIA also expects the NYMEX WTI spot price will average \$77.68 per Bbl in 2024 and then fall to \$74.98 per Bbl in 2025 when it expects production growth will slightly outpace demand growth, allowing inventories to build modestly and place some downward pressure on crude oil prices. Recent developments in the Middle East increase the risk for supply disruptions over the EIA forecast, which could result in higher and more volatile prices than the EIA currently forecast. Heightened tensions around the critical Red Sea shipping channel and other developments in the Middle East have added upward price pressure since early December 2023 and have the potential to disrupt global oil trade flows and drive up global oil prices further should they escalate or persist.

***Inflation of Cost of Goods, Services and Personnel —*** Due to the cyclical nature of the oil and gas industry, fluctuating demand for oilfield goods and services can put pressure on the pricing structure within our industry. As commodity prices rise, the cost of oilfield goods and services generally also increase, while during periods of commodity price declines, oilfield costs typically lag and do not adjust downward as fast as oil prices do. In addition, the U.S. inflation rate began increasing in 2021, peaked in the middle of 2022 and began to gradually decline in the second half of 2022. These inflationary pressures may also result in increases to the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation could likely cause the Fed and other central banks to further increase interest rates, which could have the effects of raising the cost of capital and depressing economic growth, either or both of which could hurt our business. In 2022 and 2023, the Fed raised its benchmark interest rate 11 times. The latest interest rate hike in July 2023 increased the federal funds rate to a range of 5.25%-5.50%, its highest level since 2001. The Fed wants inflation to return to its 2% goal over time, and even though inflation is declining, it is still high in absolute terms. Future changes to the benchmark interest rate remain uncertain.

***Impairment of Oil and Natural Gas Properties —*** Under the full cost method of accounting, the "ceiling test" under SEC rules and regulations specifies that evaluated and unevaluated properties' capitalized costs, less accumulated amortization and related deferred income taxes (the "Full Cost Pool"), should be compared to a formulaic limitation (the "Ceiling") each quarter on a country-by-country basis. If the Full Cost Pool exceeds the Ceiling, an impairment must be recorded. During 2023, 2022 and 2021 our ceiling test computations for our U.S. oil and gas properties did not result in a write down. At December 31, 2023, the Company's ceiling test computation was based on SEC pricing of \$78.56 per Bbl of oil, \$2.75 per Mcf of natural gas and \$18.77 per Bbl of NGLs.

If the unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the period beginning January 1, 2023 and ending December 1, 2023 used in the determination of the SEC pricing was 10% lower, resulting in \$70.73 per Bbl of oil, \$2.48 per Mcf of natural gas and \$16.89 per Bbl of NGLs, while all other factors remained constant, our oil and natural gas properties would have been impaired by \$321.9 million.

There is a significant degree of uncertainty with the assumptions used to estimate the present value of future net cash flows from estimated production of proved oil and gas reserves due to, but not limited to the risk factors referred to in Part I, Item 1A. "Risk Factors." The discounted present value of our proved reserves is a major component of the Ceiling calculation. Any decrease in pricing, negative change in price differentials, or increase in capital or operating costs could negatively impact the estimated future discounted net cash flows related to our proved oil and natural gas properties.

***BOEM Bonding Requirements —*** In 2016, BOEM issued the 2016 NTL, which bolstered supplemental bonding requirements for offshore oil and gas lessees. The 2016 NTL was first paused under the Trump Administration, and then in 2020, rescinded by BOEM. In October 2020, BOEM pursued a proposed rule published jointly with the BSEE that sought to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on oil and gas lessees (record title owners), sublessees (operating rights owners) and RUE and ROW grant holders conducting operations on the federal OCS. The DOI under the Biden Administration elected to separate BOEM and BSEE portions of the supplemental bonding requirements.

In April 2023, BSEE published its Final Rule entitled, "Risk Management, Financial Assurance, and Loss Prevention – Decommissioning Activities and Obligations," wherein BSEE clarified decommissioning responsibilities for RUE grant holders and formalized BSEE's policies regarding performance by predecessors ordered to decommission OCS facilities. The final rule withdraws the proposal in the October 2020 proposed rule to amend BSEE's regulations requiring the agency to proceed in reverse chronological order against predecessor lessees, owners of operating rights and grant holders when requiring such entities to perform their accrued decommissioning obligations upon failure to perform by current lessees, owners, or holders. Under the final rule, BSEE may issue an order to predecessors to perform accrued decommissioning obligations, including beginning maintenance and monitoring within thirty days, designating an operator for decommissioning within ninety days, and submitting a decommissioning plan within one hundred fifty days.

On June 29, 2023, BOEM published a proposed rule that, if adopted as initially proposed, would substantially revise the supplemental financial assurance requirements applicable to offshore oil and gas operations. The proposed rule would change the current criteria used to determine whether OCS lease and grant holders are required to secure supplemental financial assurance. The proposed rule would no longer use the current 5-point test in determining whether an OCS lessee or grant holder is required to obtain supplemental financial assurance and instead proposes a simplified test: (1) the credit rating of the lessee and, where applicable, (2) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. Under the proposed rule, BOEM would no longer consider or rely upon the financial strength of predecessors in determining whether, or how much, supplemental financial assurance should be provided by current lessees and grant holders. BOEM would not require supplemental financial assurance above the base bond requirements in three cases: (1) where a lessee has an investment grade credit rating (i.e., a credit rating from a Nationally Recognized Statistical Ratings Organizations, or NRSRO, that is greater than or equal to either BBB- from S&P or Baa3 from Moody's, or its equivalent, or a proxy credit rating greater than or equal to either BBB- or Baa3, as determined by the Regional Director and based upon a company's audited financial information with an accompanying auditor's certificate); (2) where there are multiple co-lessees on a lease and any one of those lessees meets the credit rating threshold; and (3) for any lease on which all lessees are rated below investment grade, where the value of the lease's proved oil and gas reserves is at least three times that of the estimated decommissioning cost estimate. BOEM proposes to phase in compliance with the new requirements over a three-year period. The extended public comment period closed on September 7, 2023, and BOEM is reviewing the comments received. At this time, we cannot predict whether BOEM will adopt the final rule in its current form or at all, the timing for any final decision, or whether any changes will result from the public notice and comment process, but will continue to monitor this rulemaking.

Moreover, BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the current interest holder's decommissioning obligations. In August 2021, BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM. We may be unable to provide the financial assurances in the amounts and under the time periods required by BOEM if it submits future demands to cover our decommissioning obligations. If in the future BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our production and other operations or cancel our applicable federal offshore leases. Our ability to obtain adequate supplemental financial assurance (pursuant to a final BOEM rule that is substantially consistent with the June 2023 proposed rule or otherwise), including the future cost of compliance with respect to supplemental bonding, could materially and adversely affect our liquidity, financial condition, cash flows, business, properties and results of operations.

***Deepwater Operations —*** We have interests in Deepwater fields in the U.S. Gulf of Mexico. Operations in Deepwater can result in increased operational risks as has been demonstrated by the Deepwater Horizon disaster in 2010. Despite technological advances since this disaster, liabilities for environmental losses, personal injury and loss of life and significant regulatory fines in the event of a disaster could be well in excess of insured amounts and result in significant current losses on our statements of operations as well as going concern issues.

***Oil Spill Response Plan —*** We maintain a Regional Oil Spill Response Plan that defines our response requirements, procedures and remediation plans in the event we have an oil spill. Oil spill response plans are generally approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. Additionally, these plans are tested and drills are conducted periodically at all levels.

***Hurricanes, Tropical Storms and Loop Currents —*** Since our operations are in the U.S. Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes, tropical storms and loop currents on production and capital projects. Significant impacts could include reductions and/or deferrals of future oil and natural gas production and revenues and increased lease operating expenses for evacuations and repairs.

***Five-Year Offshore Oil and Gas Leasing Program Update —*** Under the OCSLA, as amended, BOEM within the DOI must prepare and maintain forward-looking five-year plans—referred to by BOEM as national programs or five-year programs—to schedule proposed oil and gas lease sales on the U.S. Outer Continental Shelf. On May 11, 2022, the DOI cancelled two lease auctions in the Gulf of Mexico, Lease Sales 259 and 261 included in the 2017-2022 national program that was developed under the Obama Administration, which expired on June 30, 2022. The DOI cited "conflicting court rulings" as the primary reason for not holding the two Gulf of Mexico lease sales. The IRA, which President Biden signed into law on August 16, 2022, reinstated Lease Sale 257 held in November 2021, and required the DOI to both accept all valid high bids received in Lease Sale 257 and issue leases to the high bidders. We were one of the most active bidders in Lease Sale 257 and we were the high bidder on ten (10) blocks and awarded leases on nine (9) blocks. In January 2023, BOEM released its final environmental impact statement for Lease Sales 259 and 261 and, in March 2023, announced the results of Lease Sale 259, in which we were the high bidder on four offshore blocks, and were awarded leases on all four blocks. Lease Sale 261 was scheduled to be held on November 8, 2023, pursuant to a September 21, 2023 court order from the United States District Court for the Western District of Louisiana, as amended by a September 25, 2023 court order from the United States Court of Appeals for the Fifth Circuit. However, on October 26, 2023, the United States Court of Appeals for the Fifth Circuit stayed its and the District Court's ruling, scheduling oral arguments for November 13, 2023. On November 2, 2023, BOEM announced the postponement of Lease Sale 261 as a result of the United States Court of Appeals for the Fifth Circuit's October 26, 2023 order. Pursuant to the United States Court of Appeals for the Fifth Circuit's November 14, 2023 order, BOEM held Lease Sale 261 on December 20, 2023, in which we were the high bidder on thirteen offshore blocks and were awarded four leases as of February 16, 2024. As BOEM is still in its bid evaluation, we are awaiting BOEM's award decisions on our remaining high bids.

BOEM's development of a new five-year national program typically takes place over several years, during which successive drafts of the program are published for review and comment. At the end of the process, the Secretary of the Interior must submit the Proposed Final Program ("PFP") to the President and to Congress for a period of at least 60 days, after which the program may be approved by the Secretary of the Interior and may take effect with no further regulatory or legislative action.

BOEM took the first formal step in pursuit of a new five-year national program in January 2018 by releasing a Draft Proposed Program. The OCSLA and its implementing regulations call for two subsequent drafts, a Proposed Program ("PP"), which is open for public comment for a period of at least 90 days, and then a PFP, which is submitted to Congress and the President for 60 days before implementation. These later program stages also are accompanied by publication of a draft and final Programmatic Environmental Impact Statement ("PEIS"), with a period for public comment on the draft PEIS. The PP and a draft PEIS for the 2023-2028 five-year period were published in the Federal Register on July 8, 2022, with a 90-day comment period. The PP included no more than ten potential lease sales in the Gulf of Mexico. On September 29, 2023, the PFP for 2024-2029 was published and includes a maximum of three potential oil and gas lease sales in the Gulf of Mexico scheduled to be held in years 2025, 2027 and 2029. On December 14, 2023, the Secretary of the Interior approved the final program in a combined decision memo and Record of Decision and the final program is set to become effective on July 1, 2024.

**How We Evaluate Our Operations**

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures; and
- Adjusted EBITDA, which is discussed under "—Supplemental Non-GAAP Measure" below.

## Basis of Presentation

### *Sources of Revenues*

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs, that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives, which are reported in "Price risk management activities income (expense)" on our Consolidated Statements of Operations. The following table presents a breakout of each revenue component:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Oil | 93 % | 83 % | 86 % |
| Natural gas | 5 % | 14 % | 10 % |
| NGL | 2 % | 4 % | 4 % |

Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

***Realized Prices on the Sale of Oil, Natural Gas and NGLs —*** The NYMEX WTI prompt month oil settlement price is a widely used benchmark in the pricing of domestic oil in the United States. The actual prices we realize from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the Gulf of Mexico Basin's proximity to U.S. Gulf Coast refineries and the quality of the oil production sold in Eugene Island Crude, Louisiana Light Sweet Crude and Heavy Louisiana Sweet Crude markets.

The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices we realize from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. Currently, the sales points of our gas production are generally within close proximity to the Henry Hub which creates a minimal differential in the prices we receive for our production versus average Henry Hub prices.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue, as indicated in the table below, which provides the high, low and average prices for NYMEX WTI and NYMEX Henry Hub monthly contract prices as well as our average realized oil, natural gas, and NGL sales prices for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| **Oil:** | | | |
| NYMEX WTI high per Bbl | $ 89.43 | $ 114.84 | $ 81.48 |
| NYMEX WTI low per Bbl | $ 70.25 | $ 76.44 | $ 52.01 |
| Average NYMEX WTI per Bbl | $ 77.63 | $ 94.79 | $ 67.99 |
| Average oil sales price per Bbl (including commodity derivatives) | $ 73.59 | $ 68.40 | $ 49.67 |
| Average oil sales price per Bbl (excluding commodity derivatives) | $ 75.17 | $ 93.75 | $ 65.86 |
| **Natural Gas:** | | | |
| NYMEX Henry Hub high per MMBtu | $ 3.27 | $ 8.81 | $ 5.51 |
| NYMEX Henry Hub low per MMBtu | $ 2.14 | $ 4.38 | $ 2.62 |
| Average NYMEX Henry Hub per MMBtu | $ 2.54 | $ 6.42 | $ 3.91 |
| Average natural gas sales price per Mcf (including commodity derivatives) | $ 3.32 | $ 5.30 | $ 3.11 |
| Average natural gas sales price per Mcf (excluding commodity derivatives) | $ 2.60 | $ 7.06 | $ 3.98 |
| **NGLs:** | | | |
| NGL realized price as a % of average NYMEX WTI | 23 % | 35 % | 39 % |

To achieve more predictable cash flow, and to reduce exposure to adverse fluctuations in commodity prices, we enter into commodity derivative arrangements for a portion of our anticipated production. By removing a significant portion of price volatility associated with our anticipated production, we believe it will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, our price risk management activity may also reduce our ability to benefit from increases in prices. We will sustain losses to the extent our commodity derivatives contract prices are lower than market prices and, conversely, we will sustain gains to the extent our commodity derivatives contract prices are higher than market prices.

We will continue to use commodity derivative instruments to manage commodity price risk in the future. Our hedging strategy and future hedging transactions will be determined in accordance with both our Bank Credit Facility and Hedging Policy and may be different from what we have done on a historical basis.

***Expenses***

***Lease Operating Expense —*** Lease operating expense consists of the daily costs incurred to bring oil, natural gas and NGLs out of the underground formation and to the market, together with the daily costs incurred to maintain our producing properties. Expenses for direct labor, insurance, a portion of the HP-I lease, materials and supplies, rental and third party costs comprise the most significant portion of our lease operating expense. It further consists of costs associated with major remedial operations on completed wells to restore, maintain or improve the well's production. Because the amount of workover and maintenance expense is closely correlated to the levels of workover activity, which is not regularly scheduled, workover and maintenance expense is not necessarily comparable from period-to-period. There is a reduction in our lease operating expenses for production handling fees related to certain reimbursements for costs from certain third parties.

***Production Taxes —*** Production taxes consist of severance taxes levied by the Louisiana Department of Revenue on production of oil and natural gas from land or water bottoms within the boundaries of the state of Louisiana.

***Depreciation, Depletion and Amortization expense —*** Depreciation, depletion and amortization expense is the expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas reserves. We use the full cost method of accounting for oil and natural gas activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* for further discussion.

***Accretion Expense —*** We have obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We have obligations to plug wells when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue a liability with respect to these obligations based on our estimate of the timing and amount to replace, remove or retire the associated assets. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values.

***General and Administrative Expense —*** General and administrative expense generally consists of costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production operations, bad debt expense, equity-based compensation expense, audit and other fees for professional services and legal compliance.

***Interest Expense —*** We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Bank Credit Facility and term-based debt. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. Interest includes interest incurred under our debt agreements, the amortization of deferred financing costs (including origination and amendment fees), commitment fees, imputed interest on our capital lease, performance bond premiums and annual agency fees. Interest expense is net of capitalized interest on expenditures made in connection with exploratory projects that are not subject to current amortization.

***Price Risk Management Activities —*** We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of oil and natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

## Results of Operations

***Revenues***

The information below provides a discussion of, and an analysis of significant variance in, our oil, natural gas and NGL revenues, production volumes and sales prices (in thousands, except per unit data):

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2023** | **2022** | **Change** |
| **Revenues:** | | | |
| Oil | $ 1,357,732 | $ 1,365,148 | $ (7,416) |
| Natural gas | 68,034 | 227,306 | (159,272) |
| NGL | 32,120 | 59,526 | (27,406) |
| Total revenues | $ 1,457,886 | $ 1,651,980 | $ (194,094) |
| | | | |
| **Production Volumes:** | | | |
| Oil (MBbls) | 18,062 | 14,561 | 3,501 |
| Natural gas (MMcf) | 26,194 | 32,215 | (6,021) |
| NGL (MBbls) | 1,767 | 1,793 | (26) |
| Total production volume (MBoe) | 24,195 | 21,723 | 2,472 |
| | | | |
| **Daily Production Volumes by Product:** | | | |
| Oil (MBblpd) | 49.5 | 39.9 | 9.6 |
| Natural gas (MMcfpd) | 71.8 | 88.3 | (16.5) |
| NGL (MBblpd) | 4.8 | 4.9 | (0.1) |
| Total production volume (MBoepd) | 66.3 | 59.5 | 6.8 |
| | | | |
| **Average Sale Price per Unit:** | | | |
| Oil (per Bbl) | $ 75.17 | $ 93.75 | $ (18.58) |
| Natural gas (per Mcf) | $ 2.60 | $ 7.06 | $ (4.46) |
| NGL (per Bbl) | $ 18.18 | $ 33.20 | $ (15.02) |
| Price per Boe | $ 60.26 | $ 76.05 | $ (15.79) |
| Price per Boe (including realized commodity derivatives) | $ 59.86 | $ 56.46 | $ 3.40 |

The information below provides an analysis of the change in our oil, natural gas and NGL revenues in our Upstream Segment, due to changes in sales prices and production volumes (in thousands):

| | **Price** | **Volume** | **Total** |
|---|---|---|---|
| **Revenues:** | | | |
| Oil | $ (335,635) | $ 328,219 | $ (7,416) |
| Natural gas | (116,764) | (42,508) | (159,272) |
| NGL | (26,543) | (863) | (27,406) |
| Total revenues | $ (478,942) | $ 284,848 | $ (194,094) |

***Volumetric Analysis —*** Production volumes increased by 6.8 MBoepd to 66.3 MBoepd for the year ended December 31, 2023. The increase was primarily due to 17.6 MBoepd in production from the oil and natural gas assets acquired in the EnVen Acquisition. Additionally, production volumes increased due to the third party downtime for the HP-I dry-dock in our Phoenix Field, the Eugene Island Pipeline System shut-in primarily impacting HP-I and Green Canyon 18 Field and the Shell Odyssey Pipeline shut-in primarily impacting our Ram Powell Field, Main Pass 288 Field and non-operated Delta House facility, which resulted in 3.5 MBoepd of deferred production during 2022. These increases were partially offset by a decrease of 13.4 MBoepd due to well performance and natural production declines primarily in our Phoenix Field, Green Canyon 18 Field and Pompano Field.

***Operating Expenses***

***Lease Operating Expense***

The following table highlights lease operating expense items in total and on a cost per Boe production basis to our Upstream Segment. The information below provides the financial results and an analysis of significant variances in these results (in thousands, except per Boe data):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Lease operating expenses | $ 389,621 | $ 308,092 |
| Lease operating expenses per Boe | $ 16.10 | $ 14.18 |

Total lease operating expenses for the year ended December 31, 2023 increased by approximately $81.5 million, or 26%. The increase is primarily related to lease operating expenses of $86.8 million incurred in connection with assets acquired from the EnVen Acquisition. Additionally, there was a $11.3 million decrease in production handling fees related to reimbursements for costs from certain third parties related to our historical operations. This increase was partially offset by a $17.1 million decrease in facility and workover expense related to repairs and maintenance at the Phoenix Field compared to the same period in 2022.

***Depreciation, Depletion and Amortization***

The following table highlights depreciation, depletion and amortization items. The information below provides the financial results and an analysis of significant variances in these results (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Depreciation, depletion and amortization | $ 663,534 | $ 414,630 |

Depreciation, depletion and amortization expense for the year ended December 31, 2023 increased by approximately $248.9 million, or 60%. This increase was primarily due to an increase of $8.28 per Boe, or 44% in the depletion rate on our proved oil and natural gas properties due to an increase in our proved properties and related production primarily related to the assets acquired as part of the EnVen Acquisition, which resulted in $176.3 million of additional depletion. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures*" for further discussion on the EnVen Acquisition. Additionally, the depletion rate increased due to the extension of the HP-I lease during the fourth quarter of 2022. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 5 — *Leases* for additional information on the HP-I lease extension.

***General and Administrative Expense***

The following table highlights general and administrative expense items in total and on a cost per Boe production basis for the Upstream Segment. The information below provides the financial results and an analysis of significant variances in these results (in thousands, except per Boe data):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Upstream Segment | $ 139,026 | $ 82,979 |
| CCS Segment | 11,922 | 10,240 |
| Unallocated corporate | 7,545 | 6,535 |
| Total general and administrative expense | $ 158,493 | $ 99,754 |
| | | |
| Upstream general and administrative expense per Boe | $ 5.75 | $ 3.82 |

General and administrative expense for the year ended December 31, 2023, increased by approximately $58.7 million, or 59%. This increase was primarily related to higher Upstream Segment transaction costs for the closing and continued integration of the EnVen Acquisition of $31.4 million or $1.26 per Boe. The Upstream Segment also had an increase in legal fees of $5.1 million or $0.21 per Boe due to the Dunwoody litigation assumed as part of the EnVen Acquisition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies* for further discussion. Additionally, there was an increase in payroll expense due to additional employee headcount primarily related to the EnVen Acquisition. These increases were partially offset by a decrease in non-cash equity-based compensation of $3.0 million, primarily due to a forfeiture during the third quarter of 2023.

***Miscellaneous***

The following table highlights miscellaneous items in total. The information below provides the financial results and an analysis of significant variances in these results (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | **2023** | **2022** |
| Accretion expense | $ 86,152 | $ 55,995 |
| Other operating (income) expense | $ (52,155) | $ 33,902 |
| Interest expense | $ 173,145 | $ 125,498 |
| Price risk management activities (income) expense | $ (80,928) | $ 272,191 |
| Equity method investment (income) expense | $ (3,209) | $ (14,222) |
| Other (income) expense | $ (12,371) | $ (31,800) |
| Income tax (benefit) expense | $ (60,597) | $ 2,537 |

***Accretion Expense*** — During the year ended December 31, 2023, we recorded $86.2 million of accretion expense compared to $56.0 million during the year ended December 31, 2022. The change is primarily the result of the increase in accretion associated with the asset retirement obligations assumed as part of the EnVen Acquisition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for further discussion.

***Other Operating (Income) Expense*** — During the year ended December 31, 2023, we recognized a gain of $66.2 million on the Mexico Divestiture. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for further discussion. This gain was partially offset by $11.9 million of estimated decommissioning obligations primarily as a result of unrelated parties or counterparties that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. During the year ended December 31, 2022, we recorded $31.6 million of estimated decommissioning obligations. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies*.

***Interest Expense*** — During the year ended December 31, 2023, we recorded $173.1 million of interest expense compared to $125.5 million during the year ended December 31, 2022. The change is primarily a result of the increase in interest associated with the 11.75% Notes assumed as part of the EnVen Acquisition. Additionally, there was an increase in interest associated with the Bank Credit Facility due to increased interest rates and average borrowings when compared to the same period in 2022. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

***Price Risk Management Activities —*** Price risk management activities for year ended December 31, 2023 resulted in a decrease of approximately $353.1 million, or 130%. The income of $80.9 million for the year ended December 31, 2023 consisted of $90.4 million in non-cash gains from the increase in the fair value of our open derivative contracts offset by $9.5 million in cash settlement losses. The expense of $272.2 million for the year ended December 31, 2022 consisted of $425.6 million in cash settlement losses and $153.4 million in non-cash gains from the increase in the fair value of our open derivative contracts.

These unrealized gains and losses on open derivative contracts relate to production for future periods; however, changes in the fair value of all of our open derivative contracts are recorded as a gain or loss on our Consolidated Statements of Operations at the end of each month. As a result of the derivative contracts we have on our anticipated production volumes through December 2025, we expect these activities to continue to impact net income (loss) based on fluctuations in market prices for oil and natural gas. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for additional information.

***Equity Method Investment Income*** — During the year ended December 31, 2023, we recorded $12.1 million of equity losses offset by an $8.6 million gain on the funding of the capital carry of our investment in Bayou Bend by Chevron. During the year ended December 31, 2022, we recorded a $13.9 million gain on the partial sale and $1.4 million gain on the funding of the capital carry of our equity method investment in Bayou Bend offset by equity losses of $1.1 million. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments* for additional information.

***Other (Income) Expense*** — During the year ended December 31, 2022, we recorded a $27.5 million gain as a result of the settlement agreement to resolve a previously pending litigation that was filed in October 2017 that is further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies*. This was partially offset by a $1.6 million loss on extinguishment of debt as a result of the redemption of the 12.00% Notes further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

***Income Tax Benefit (Expense) —*** During the year ended December 31, 2023, we recorded $60.6 million of income tax benefit compared to $2.5 million of income tax expense during the year ended December 31, 2022, primarily due to a non-cash tax benefit of $106.8 million related to the release of the valuation allowance for our deferred tax assets partially offset with an income tax expense of $31.1 million related to current year activity inclusive of permanent differences for the year ended December 31, 2023. The realization of our deferred tax asset depends on recognition of sufficient future taxable income in specific tax jurisdictions in which temporary differences or net operating losses relate. In assessing the need for a valuation allowance, we consider whether it is more likely than not that some portion of the deferred tax assets will not be realized. See additional information on the valuation allowance as described in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Income Taxes*.

**Commitments and Contingencies**

For a further discussion of our commitments and contingencies, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies*. Additionally, we are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuit with certainty, but our management believes it is remote that any such pending or threatened lawsuit will have a material adverse impact on our financial condition. See Part I, Item 3. Legal Proceedings for additional information.

Due to the nature of our business, we are, from time-to-time, involved in other routine litigation or subject to disputes or claims related to business activities, including workers' compensation claims, employment related disputes and civil penalties by regulators. In the opinion of our management, none of these other pending litigations, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Part I, Item 3. Legal Proceedings for additional information.

**Supplemental Non-GAAP Measure**

***EBITDA and Adjusted EBITDA***

"EBITDA" and "Adjusted EBITDA" are non-GAAP financial measures used to provide management and investors with (i) additional information to evaluate, with certain adjustments, items required or permitted in calculating covenant compliance under our debt agreements, (ii) important supplemental indicators of the operational performance of our business, (iii) additional criteria for evaluating our performance relative to our peers and (iv) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP or as alternatives to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

We define these as the following:

- ***EBITDA —*** Net income (loss) plus interest expense, income tax expense (benefit), depreciation, depletion and amortization, and accretion expense.
- ***Adjusted EBITDA —*** EBITDA plus non-cash write-down of oil and natural gas properties, transaction and other (income) expenses, decommissioning obligations, the net change in the fair value of derivatives (mark to market effect, net of cash settlements and premiums related to these derivatives), (gain) loss on debt extinguishment, non-cash write-down of other well equipment and non-cash equity-based compensation expense.

The following table presents a reconciliation of the GAAP financial measure of net income (loss) to Adjusted EBITDA for each of the periods indicated (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Net income (loss) | $ 187,332 | $ 381,915 | $ (182,952) |
| Interest expense | 173,145 | 125,498 | 133,138 |
| Income tax expense (benefit) | (60,597) | 2,537 | (1,635) |
| Depreciation, depletion and amortization | 663,534 | 414,630 | 395,994 |
| Accretion expense | 86,152 | 55,995 | 58,129 |
| EBITDA | 1,049,566 | 980,575 | 402,674 |
| Write-down of oil and natural gas properties | — | — | 18,123 |
| Transaction and other (income) expense[(1)] | (33,295) | (34,513) | 5,886 |
| Decommissioning obligations[(2)] | 11,879 | 31,558 | 21,055 |
| Derivative fair value (gain) loss[(3)] | (80,928) | 272,191 | 419,077 |
| Net cash received (paid) on settled derivative instruments[(3)] | (9,457) | (425,559) | (290,164) |
| (Gain) loss on debt extinguishment | — | 1,569 | 13,225 |
| Non-cash write-down of other well equipment | — | — | 5,606 |
| Non-cash equity-based compensation expense | 12,953 | 15,953 | 10,992 |
| Adjusted EBITDA | $ 950,718 | $ 841,774 | $ 606,474 |

(1) Transaction expenses include $40.4 million and $9.0 million in costs related to the EnVen Acquisition, inclusive of $25.3 million and nil in severance expenses for the years ended December 31, 2023 and 2022, respectively. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* and Note 10 — *Employee Benefit Plans and Share-Based Compensation*. Other income (expense) includes restructuring expenses, cost saving initiatives and other miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance. For the year ended December 31, 2023, the amount includes a $66.2 million gain on the Mexico Divestiture. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures*. The amount includes a gain on the funding of the capital carry of our investment in Bayou Bend by Chevron of $8.6 million and $1.4 million for the year ended December 31, 2023 and 2022, respectively. Additionally, it includes a $13.9 million gain on the partial sale of our investment in Bayou Bend to Chevron for the year ended December 31, 2022. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments*. For the year ended December 31, 2022, the amount includes $27.5 million gain as a result of the settlement agreement to resolve previously pending litigation that was filed in October 2017 that is further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies*.

(2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies* for additional information on decommissioning obligations.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts (payments) on settled commodity derivative instruments have the effect of adjusting net loss for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on an unrealized basis during the period the derivatives settled.

### Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our Bank Credit Facility. Our primary uses of cash are for capital expenditures, working capital, debt service, share repurchases and for general corporate purposes. The cost of borrowing under our Bank Credit Facility has increased. By raising its federal funds rate, the Fed is making it more expensive to borrow money. Our working capital deficit has decreased since December 31, 2022 primarily due to a decrease of $61.1 million in liabilities from price risk management activities and an increase of $11.1 million in assets from price risk management activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for additional information. As of December 31, 2023, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $787.9 million.

We fund drilling, completions and development activities primarily through operating cash flows, cash on hand and through borrowings under the Bank Credit Facility, if necessary. Historically, we have funded significant acquisitions with the issuance of senior notes, borrowings under the Bank Credit Facility and through additional equity issuances. We occasionally adjust our capital budget in response to changing operating cash flow forecasts and market conditions, including the prices of oil, natural gas and NGLs, acquisition opportunities and the results of our exploration and development activities. We are continuing to explore a capital raise to finance the accelerated growth of our CCS segment.

***Capital Expenditures —*** The following is a table of our capital expenditures, excluding acquisitions, for the year ended December 31, 2023 (in thousands):

| | | |
|---|---|---|
| U.S. drilling & completions | $ | 447,254 |
| Mexico appraisal & exploration | | 291 |
| Asset management[(1)] | | 83,970 |
| Seismic and G&G, land, capitalized G&A and other | | 64,955 |
| Total Upstream capital expenditures | | 596,470 |
| Plugging & abandonment | | 86,615 |
| Decommissioning obligations settled[(2)] | | 50,584 |
| Total Upstream | | 733,669 |
| Investment in CCS | | 40,961 |
| Total | $ | 774,630 |

(1) Asset management consists of capital expenditures for development-related activities primarily associated with recompletions and improvements to our facilities and infrastructure.

(2) Settlement of decommissioning obligations as a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies* for additional information on decommissioning obligations.

Based on our current level of operations and available cash, we believe our cash flows from operations, combined with availability under the Bank Credit Facility, provide sufficient liquidity to fund our board approved 2024 Upstream capital spending program of $565.0 million to $595.0 million and plugging & abandonment and decommissioning obligations of $90.0 million to $100.0 million. However, our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the Bank Credit Facility, and (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, depends on operating and economic conditions, some of which are beyond our control. To the extent possible, we have attempted to mitigate certain of these risks (e.g. by entering into oil and natural gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production), but we could be required to, or we or our affiliates may from time to time, take additional future actions on an opportunistic basis. To address further changes in the financial and/or commodity markets, future actions may include, without limitation, issuing debt, including secured debt, or issuing equity to directly or independently repurchase or refinance our outstanding indebtedness.

***Common Stock Repurchase Program —*** Our Board of Directors authorized a stock repurchase program on March 20, 2023 with an approved limit of $100.0 million and no set term limits. In March and June of 2023, we repurchased 1.9 million shares for $26.6 million and 1.5 million shares for $20.9 million, respectively. As of December 31, 2023, there is $52.5 million remaining under the authorized program. All repurchased shares are held in treasury.

Repurchases may be made from time to time in the open market, in privately negotiated transactions, or by such other means as will comply with applicable state and federal securities laws. The timing of any repurchases under the share repurchase program will depend on market conditions, contractual limitations and other considerations. The program may be extended, modified, suspended or discontinued at any time, and does not obligate the Company to repurchase any dollar amount or number of shares.

The IRA 2022 provides for, among other things, the imposition of a new 1% U.S. federal excise tax on certain repurchases of stock by publicly traded U.S. corporations such as us after December 31, 2022. Accordingly, the excise tax applies to our share repurchase program. The excise tax payment is non-deductible for income tax purposes. Subject to certain exceptions and adjustments, the excise tax equals 1% of the fair market value of the stock repurchased by a corporation during the applicable tax year. The repurchase amount subject to the excise tax is generally reduced by the fair market value of any stock issued by a corporation during a taxable year, including the fair market value of any stock issued or provided to employees of a corporation or employees of certain of its subsidiaries. The current federal administration has proposed increasing the excise tax amount from 1% to 4%; however, it is unclear whether such a change in the amount of the excise tax will be enacted and, if enacted, how soon any change can take effect. We do not anticipate paying any excise tax in 2023 based on the fair market value of the stock issuance in connection to the EnVen Acquisition.

***Overview of Cash Flow Activities —*** The following table summarizes cash flows provided by (used in) by type of activity, for the following periods (in thousands):

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| | 2023 | | 2022 | |
| Operating activities | $ | 519,069 | $ | 709,739 |
| Investing activities | $ | (512,626) | $ | (311,977) |
| Financing activities | $ | 85,411 | $ | (423,469) |

***Operating Activities —*** Net cash provided by operating activities decreased $190.7 million in 2023 compared to 2022 primarily attributable to a decrease in revenues combined with an increase in lease operating expense of $275.6 million.

***Investing Activities*** — Net Cash used in investing activities increased $200.6 million in 2023 compared to 2022 primarily due to an increase in capital expenditures of $238.3 million. The capital expenditure budget for 2023 included projects related to the EnVen Acquisition. Additionally, we had an increase in contributions to equity method investees of $27.2 million and investment in intangibles of $12.4 million. This was offset by cash proceeds of $74.9 million from the Mexico Divestiture. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***Financing Activities —*** Net cash used in financing activities increased $508.9 million in 2023 compared to 2022. We had net borrowings from the Bank Credit Facility of $200.0 million for the year ended December 31, 2023 due to the funding of the EnVen Acquisition, working capital needs and capital expenditures. We had net repayments of $375.0 million during the same period in 2022 due to a management goal to reduce our leverage ratio coupled with a commodity price environment that supported debt repayments to achieve such goal. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information on the EnVen Acquisition. We repurchased $47.5 million of our common stock through our share repurchase program during the year ended December 31, 2023. See the subsection entitled "— Common Stock Repurchase Program" for additional information. Additionally, there was an increase in redemption of senior notes of $11.8 million and deferred financing costs of $11.6 million in each case when compared to the same period in 2022. For additional details on our debt, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

***Overview of Debt Instruments***

***Financing Arrangements —*** As of December 31, 2023, total debt, net of discount and deferred financing costs, was approximately $1,025.7 million, comprised of our $866.0 million aggregate principal amount of the 12.00% Notes and 11.75% Notes (as defined herein) and $200.0 million outstanding under our Bank Credit Facility. We were in compliance with all debt covenants at December 31, 2023. For additional details on our debt, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

***Bank Credit Facility – matures March 2027 —*** We maintain a Bank Credit Facility with a syndicate of financial institutions. The Bank Credit Facility provides for determination of the borrowing base based on our proved producing reserves and a portion of our proved undeveloped reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter each year. For additional details on our Bank Credit Facility, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

***12.00% Second-Priority Senior Secured Notes—due January 2026 —*** The 12.00% Notes were issued pursuant to an indenture dated January 4, 2021 and the first supplemental indenture dated January 14, 2021 between Talos Energy Inc. (the "Parent Guarantor"); Talos Production Inc. (the "Issuer"); the Subsidiary Guarantors (defined below); and Wilmington Trust, National Association, as trustee and collateral agent. The 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indentures. The 12.00% Notes were secured on a second-priority senior secured basis by liens on substantially the same collateral as the collateral securing the Issuer's existing first-priority obligations under its Bank Credit Facility. The 12.00% Notes were scheduled to mature on January 15, 2026 and had interest payable semi-annually each January 15 and July 15. We made an interest payment of $38.3 million on January 16, 2024. For additional details on the 12.00% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

On January 23, 2024, we issued a conditional notice to redeem in full the 12.00% Notes at a redemption price of 103.000% of the principal amount thereof, plus accrued and unpaid interest to, but excluding, the redemption date, in accordance with the 12.00% Notes indenture. The 12.00% Notes were redeemed on February 7, 2024 for $662.4 million utilizing the net proceeds from the Debt Offering.

***11.75% Senior Secured Second Lien Notes—due April 2026*** — On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Company assumed EnVen's 11.75% Senior Secured Second Lien Notes due 2026 (the "11.75% Notes") with a principal amount of $257.5 million. The 11.75% Notes were scheduled to mature on April 15, 2026 and interest accrued and was paid semi-annually in cash in arrears on April 15$^{th}$ and October 15$^{th}$ of each year. The 11.75% Notes were secured on a second-priority senior secured basis by liens on substantially the same collateral as the collateral securing the Issuer's existing first-priority obligations under its Bank Credit Facility. The indenture governing the 11.75% Notes required the redemption of $15.0 million of the principal amount outstanding at par value on April 15$^{th}$ and October 15$^{th}$ of each year. For additional details on the 11.75% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

On January 26, 2024, we issued a conditional notice to redeem in full the 11.75% Notes at a redemption price of 102.938% of the principal amount thereof, plus accrued and unpaid interest to, but excluding, the redemption date, in accordance with the 11.75% Notes indenture. We irrevocably deposited funds with the trustee sufficient to satisfy and discharge the 11.75% Notes indenture and the 11.75% Notes until redeemed on April 15, 2024 with the funds deposited with the trustee and elected to satisfy and discharge the 11.75% Notes indenture in accordance with its terms and the 11.75% Notes trustee acknowledged such discharge and satisfaction. We deposited $247.5 million with the trustee on February 7, 2024 utilizing the net proceeds from the Debt Offering.

***9.000% Second-Priority Senior Secured Notes—due February 2029*** — The 9.000% Notes were issued pursuant to the 9.000% Notes indenture. The 9.000% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indenture. The 9.000% Notes are secured on a second-priority senior secured basis by liens on substantially the same collateral as the collateral securing the Issuer's existing first-priority obligations under its Bank Credit Facility. The 9.000% Notes mature on February 1, 2029 and have interest payable semi-annually each February 1 and August 1.

***9.375% Second-Priority Senior Secured Notes—due February 2031*** — The 9.375% Notes were issued pursuant to the 9.375% Notes indenture. The 9.375% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indenture. The 9.375% Notes are secured on a second-priority senior secured basis by liens on substantially the same collateral as the collateral securing the Issuer's existing first-priority obligations under its Bank Credit Facility. The 9.375% Notes mature on February 1, 2031 and have interest payable semi-annually each February 1 and August 1.

***Guarantor Financial Information* —** We own no operating assets and have no operations independent of our subsidiaries. The 12.00% Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by the Parent Guarantor and on a second-priority senior secured basis by each of the Issuer's present and future direct or indirect wholly owned material restricted subsidiaries that guarantees the Issuer's Bank Credit Facility (collectively, the "Subsidiary Guarantors" and, together with the Parent Guarantor, the "Guarantors"). Our non-domestic subsidiaries (other than Talos International Holdings SCS) and our unrestricted CCS domestic subsidiaries (the "Non-Guarantors") are 100% owned by us but do not guarantee the 12.00% Notes.

In lieu of providing separate financial statements for the Issuer and the Guarantors, we have presented the accompanying supplemental summarized combined balance sheet and statement of operations information for the Issuer and the Guarantors on a combined basis after elimination of intercompany transactions and amounts related to investment in any subsidiary that is a Non-Guarantor**.**

The following table presents the balance sheet information for the respective periods (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Current assets | $ 409,112 | $ 344,525 |
| Non-current assets | 4,352,102 | 2,571,254 |
| Total assets | $ 4,761,214 | $ 2,915,779 |
| | | |
| Current liabilities | $ 577,587 | $ 599,669 |
| Non-current liabilities | 2,082,543 | 1,285,992 |
| Talos Energy Inc. stockholders' equity | 2,101,084 | 1,030,118 |
| Total liabilities and stockholders' equity | $ 4,761,214 | $ 2,915,779 |

The following table presents the income statement information (in thousands):

| | Year Ended December 31, 2023 |
|---|---|
| Revenues | $ 1,457,886 |
| Costs and expenses | (1,258,327) |
| Net income (loss) | $ 199,559 |

***Material Cash Requirements* —** We are party to various contractual obligations. Some of these obligations may be reflected in our accompanying Consolidated Financial Statements, while other obligations, such as certain operating leases and capital commitments, are not reflected on our accompanying Consolidated Financial Statements.

The following table and discussion summarizes our material cash requirements from known contractual obligations as of December 31, 2023 (in thousands):

| | 2024 | 2025 | 2026 | 2027 | 2028 | Thereafter | Total[5] |
|---|---|---|---|---|---|---|---|
| Long-term financing obligations: | | | | | | | |
| Debt principal | $ 30,000 | $ 30,000 | $ 806,041 | $ 200,000 | $ — | $ — | $ 1,066,041 |
| Debt interest | 123,084 | 119,559 | 68,975 | 5,152 | — | — | 316,770 |
| Vessel commitments[1] | 13,216 | — | — | — | — | — | 13,216 |
| Derivative liabilities | 7,305 | 795 | — | — | — | — | 8,100 |
| Operating lease obligations | 4,748 | 4,716 | 4,803 | 4,708 | 4,610 | 4,584 | 28,169 |
| Finance lease[2] | 19,336 | — | — | — | — | — | 19,336 |
| Purchase obligations[3] | 3,083 | — | — | — | — | — | 3,083 |
| Other commitments[4] | 3,991 | 327 | — | — | — | — | 4,318 |
| Total contractual obligations[5] | $ 204,763 | $ 155,397 | $ 879,819 | $ 209,860 | $ 4,610 | $ 4,584 | $ 1,459,033 |

(1) Includes vessel commitments we will utilize for certain Deepwater well intervention, drilling operations and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will be billed for their working interest share of such costs.
(2) Lease agreement for the HP-I floating production facility in the Phoenix Field.
(3) Includes committed purchase orders to execute planned future drilling activities.
(4) Includes commitments associated with our CCS Segment relating to an equity funding obligation and payments required under a sequestration agreement.
(5) This table does not include our estimated discounted liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $897.2 million as of December 31, 2023. For additional information regarding these liabilities, please see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 9 — *Asset Retirement Obligations*. Additionally, this table does not include liabilities associated with our decommissioning obligations. For additional information regarding our decommissioning obligations, please see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitment and Contingencies*.

Debt principal of $638.5 million associated with the 12.00% Notes reflected in the table above was redeemed on February 7, 2024 from proceeds from the Debt Offering. There was $191.8 million of interest reflected in the table above associated with the 12.00% Notes. Debt principal of $227.5 million associated with the 11.75% Notes reflected in the table above will be redeemed on April 15, 2024 from proceeds from the Debt Offering. There was $58.0 million of interest reflected in the table above associated with the 11.75% Notes. The New Senior Notes have an aggregate principal amount of $1,250.0 million with interest of $688.9 million over the life of the New Senior Notes.

***Performance Obligations —*** As of December 31, 2023, we had secured performance bonds totaling $1.4 billion primarily related to plugging and abandonment of wells and removal of facilities in the U.S. Gulf of Mexico and certain obligations under the PSCs with Mexico from third party sureties. Additionally, we had secured letters of credit issued under our Bank Credit Facility totaling $10.8 million. Letters of credit that are outstanding reduce the available revolving credit commitments. See the subsection entitled "— Known Trends and Uncertainties — BOEM Bonding Requirements" for additional information on the future cost of compliance with respect to BOEM supplemental bonding requirements that could have a material adverse effect on our business, properties, results of operations and financial condition.

For additional information about certain of our obligations and contingencies, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Commitments and Contingencies*.

**Critical Accounting Policies and Estimates**

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense, and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates. Our significant accounting policies are described in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies*.

***Proved Reserve Estimates*** — We account for our oil and natural gas producing activities using the full cost method of accounting, which is dependent on the estimation of proved reserves to determine the rate at which we record depletion on our oil and natural gas properties and whether the value of our evaluated oil and natural gas properties is permanently impaired based on the quarterly full cost ceiling impairment test.

We estimate our proved oil, natural gas and NGL reserves in accordance with the guidelines established by the SEC. Proved oil, natural gas and NGL reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future periods from known reservoirs and under existing economic conditions, operating methods and governmental regulations. Prices are determined using SEC pricing.

Our estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. The estimates of proved reserves are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in price, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date. A material adverse change in the estimated volumes of proved reserves could have a negative impact on depreciation, depletion and amortization or could result in property impairments.

The depletion of our proved oil and natural gas properties is calculated using the unit-of-production method based on proved oil and gas reserves. If the proved reserves used had been a 10 percent lower, depreciation, depletion and amortization in the three months ended December 31, 2023 would have increased by an estimated $19.4 million. Furthermore, the Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Downward revisions of previous reserve quantity estimates accounted for approximately $484.4 million of the standardized measure of our total reserves from December 31, 2022 to December 31, 2023. The Company's ceiling test computations did not result in a write-down of its U.S. oil and natural gas properties during the years ended December 31, 2023, 2022 and 2021.

***Asset Retirement Obligations*** — The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate in the table below represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as "Accretion expense" on the Company's Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for asset retirement obligations, the Company recognizes the difference as an adjustment to proved properties.

***Income Taxes*** — Our provision for income taxes includes U.S. state and federal and foreign taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. 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 and carryforwards 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 in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2023, we believe it is more likely than not that some or all of the benefits from our state deferred tax assets will not be realized and reduced the state deferred tax assets by a valuation allowance.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

***Determination of Fair Value in Business Combinations*** — We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. The amount of goodwill or bargain purchase gain recognized, if any, is determined based on the consideration transferred compared to the acquisition date amounts of the identifiable net assets acquired.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties.

The fair value of proved and oil natural gas properties as of the acquisition date are based on estimated proved oil, natural gas and NGL reserves and related discounted future net cash flows. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices, and a weighted average cost of capital discount rate. When estimating the fair value of proved and unproved properties, additional risk adjustments are applied to proved developed non-producing, proved undeveloped, probable and possible reserves to reflect the relative uncertainty of each reserve class.

The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value. Historically there has been significant volatility in oil, natural gas and NGL prices and estimates of such future prices are inherently imprecise. Additionally, the actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. A higher discount rate decreases the net present value of cash flows.

**Recently Adopted Accounting Standards**

None.

**Recently Issued Accounting Standards**

Information on Recently Issued Accounting Standards that could potentially impact our consolidated financial statements and related disclosures is incorporated by reference to Part IV, Item 15. Exhibit and Financial Statement Schedules — Note 1 — *Organization, Nature of Business and Basis of Presentation.*

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: commodity prices and, to a lesser extent, interest rate risk. Our risk management activities involve the use of derivative financial instruments to mitigate the impact of market price risk exposures primarily related to our oil and natural gas production.

We are subject to a minimum hedging requirement under our Bank Credit Facility for each calendar month on a six-full fiscal quarter rolling basis. For any quarter occurring during the first four forward fiscal quarters, we are required to hedge a minimum of 50% of our reasonably anticipated projected production from proved developed producing reserves from the semi-annual reserves report delivered to the administrative agent of our Bank Credit Facility, adjusted to 45% in July and November and 25% in August, September and October. For the fifth and sixth forward fiscal quarters, if the Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) is greater than or equal to 1.00 to 1.00, then we are required to hedge a minimum of 25%, adjusted to 20% in August, September and October.

All derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded as “Price risk management activities income (expense)” on the Consolidated Statements of Operations in each period.

**Commodity Price Risks**

Oil and natural gas prices can fluctuate significantly and have a direct impact on our revenues, earnings and cash flow. During year ended December 31, 2023, our average oil price realizations after the effect of derivatives increased 8% to $73.59 per Bbl from $68.40 per Bbl in the comparable 2022 period. Our average natural gas price realizations after the effect of derivatives decreased 37% during the year ended December 31, 2023 to $3.32 per Mcf from $5.30 per Mcf in the comparable 2022 period.

**Price Risk Management Activities**

We have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of oil and natural gas swaps. These contracts will impact our earnings as the fair value of these derivatives changes. Our derivatives will not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we will be subject to commodity price risks on our remaining forecasted production.

We had commodity derivative instruments in place to reduce the price risk associated with future production of 9,833 MBbls of crude oil and 15,515 MMBtu of natural gas at December 31, 2023, with a net derivative asset position of $45.6 million. For additional information regarding our commodity derivative instruments, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments*, included elsewhere in this Annual Report. The table below presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at December 31, 2023 (in thousands):

| | | Oil and Natural Gas Derivatives | | | |
|---|---|---|---|---|---|
| | | Ten Percent Increase | | Ten Percent Decrease | |
| | Fair Value | Fair Value | Change | Fair Value | Change |
| Price impact[(1)] | $ 45,603 | $ (21,481) | $ (67,084) | $ 113,601 | $ 67,998 |

(1) Presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from changes in oil and natural gas prices.

### Variable Interest Rate Risks

We had total debt outstanding of $1,066.0 million at December 31, 2023, before unamortized original issue discount and deferred financing costs. Of this, $866.0 million aggregate principal was from our 12.00% Notes and 11.75% Notes, which bears interest at a fixed rate. The remaining $200.0 million is from outstanding borrowings under our Bank Credit Facility with variable interest rates. We are subject to the risk of changes in interest rates under our Bank Credit Facility. In addition, the terms of our Bank Credit Facility require us to pay higher interest rates as we utilize a larger percentage of our available borrowing base. We manage our interest rate exposure by maintaining a combination of fixed and variable rate debt and monitoring the effect of market changes in interest rates. As of December 31, 2023, our interest rate risk exposure is mitigated as a result of fixed interest rates on 81% of our debt. The all-in interest rate on our variable rate debt at December 31, 2023 was 8.26%, which includes a spread of 2.85% based on the utilization rate of our Bank Credit Facility, and a secured overnight financing rate (”SOFR”) of 5.41%. A 10% change in the SOFR rate on this variable rate debt balance at December 31, 2023 would change interest expense for the year ended December 31, 2023 by approximately $1.1 million. For additional information regarding the borrowing base utilization percentage associated with our Bank Credit Facility, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*, included elsewhere in this Annual Report.

## Item 8. Financial Statements and Supplementary Data

See the Consolidated Financial Statements and Report of Independent Registered Public Accounting Firm as of December 31, 2023 and 2022 and for the years ended December 31, 2023, 2022 and 2021, included in Part IV, Item 15. Exhibits and Financial Statements Schedules.

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

None.

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness 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. Based on such evaluation, our chief executive officer and chief financial officer have concluded that as of December 31, 2023, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of SEC, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosures.

### Management’s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Management conducted an assessment of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on the assessment, management has concluded that its internal control over financial reporting was effective as of December 31, 2023 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. Our independent registered public accounting firm, Ernst & Young LLP, has issued an audit report with respect to our internal control over financial reporting, which is included in this Annual Report.

### Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the fourth quarter of 2023 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Item 9B. Other Information

During the three months ended December 31, 2023, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K.

### Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspection

Not applicable.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference to our Proxy Statement for the 2024 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2023.

Our Board of Directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (*www.talosenergy.com*) under “Corporate Governance” within the “Investors” tab. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on the website address and location specified above.

### Item 11. Executive Compensation

The information required by this item is incorporated by reference to our Proxy Statement for the 2024 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2023.

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

The information required by this item is incorporated by reference to our Proxy Statement for the 2024 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2023.

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

The information required by this item is incorporated by reference to our Proxy Statement for the 2024 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2023.

### Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2024 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2023.

## PART IV

### Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

(1) **Financial Statements:**

Refer to the Index to Consolidated Financial Statements on page F-1 for a list of all financial statements filed as part of this Annual Report on Form 10-K.

(2) **Financial Statement Schedules:**

Other than as stated on the Index to Consolidated Financial Statements on page F-1 with respect to Schedule I, financial statement schedules have been omitted because they are either not material, not required, not applicable or the information required to be presented is included in our Consolidated Financial Statements and related notes.

(3) **Exhibits:**

| Exhibit Number | Description |
|---|---|
| 2.1# | Agreement and Plan of Merger, dated as of September 21, 2022, by and among Talos Energy Inc., Talos Production Inc., Tide Merger Sub I Inc., Tide Merger Sub II LLC, Tide Merger Sub III LLC, BCC Enven Investments, L.P. and EnVen Energy Corporation (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022). |
| 2.2# | Agreement and Plan of Merger, dated as of January 13, 2024, by and among Talos Energy Inc., QuarterNorth Energy Inc., Compass Star Merger Sub Inc. and the Equityholder Representatives named therein (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 16, 2024). |
| 3.1 | Second Amended and Restated Certificate of Incorporation of Talos Energy Inc. (incorporated by reference to Exhibit 3.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023). |
| 3.2 | Second Amended and Restated Bylaws of Talos Energy Inc. (incorporated by reference to Exhibit 3.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023). |
| 4.1 | Indenture, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021). |
| 4.2 | Form of Stock Certificate for Common Stock of Talos Energy Inc. (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Amendment No. 1 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on February 9, 2018). |
| 4.3 | First Supplemental Indenture, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021). |
| 4.4 | Indenture, dated as of February 7, 2024, and by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee, pursuant to which the 2029 Notes were issued. (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 7, 2024). |
| 4.5 | Indenture, dated as of February 7, 2024, and by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee, pursuant to which the 2031 Notes were issued. (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 7, 2024). |
| 4.6 | Form of 12.00% Second-Priority Senior Secured Note due 2026 (included as Exhibit A to Exhibit 4.6 hereto) (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021). |
| 4.7 | Form of 9.000% Second-Priority Senior Secured Note due 2029 (included as Exhibit A to Exhibit 4.4 hereto) (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 7, 2024). |

| | |
|---|---|
| 4.8 | Form of 9.375% Second-Priority Senior Secured Note due 2031 (included as Exhibit A in Exhibit 4.5 hereto) (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 7, 2024). |
| 4.9 | Registration Rights Agreement, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021). |
| 4.10 | Registration Rights Agreement, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021). |
| 4.11 | Registration Rights Agreement, dated September 21, 2022, by and among Talos Energy Inc. and the Persons listed on Schedule A thereto (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022). |
| 4.12 | Description of Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.10 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on March 1, 2023). |
| 4.13 | Second Supplemental Indenture, dated as of October 27, 2022, among Talos Production Inc., the Guarantors named therein and Wilmington Trust National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on October 28, 2022). |
| 4.14 | Indenture, dated as of April 15, 2021, by and among Energy Ventures GoM LLC, EnVen Finance Corporation, Talos Production Inc. (as successor in interest to EnVen Energy Corporation), the other guarantors party thereto and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023). |
| 4.15 | Second Supplemental Indenture, dated as of February 13, 2023, among Talos Production Inc., each of the other guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023). |
| 4.16 | Third Supplemental Indenture, dated as of February 13, 2023, among Talos Production Inc., Energy Ventures GoM LLC, EnVen Finance Corporation, each of the other guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023). |
| 10.1 | Credit Agreement, dated as of May 10, 2018, by and among Talos Production LLC, as borrower, Talos Energy Inc., as holdings, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders named therein (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K12B/A filed with the SEC on July 18, 2018). |
| 10.2 | Intercreditor Agreement, dated as of May 10, 2018, between JPMorgan Chase Bank, N.A., as First Lien Agent, and Wilmington Trust, National Association, as Second Lien Agent (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018). |
| 10.3† | Offer Letter between Talos Energy Inc. and Shannon Young, dated as of April 13, 2019 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on April 24, 2019). |
| 10.4† | Offer Letter between Talos Energy Inc. and Robert D. Abendschein, dated as of December 26, 2019 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 23, 2020). |
| 10.5† | Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and Timothy S. Duncan (incorporated by reference to Exhibit 10.10 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018). |
| 10.6† | Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and John A. Parker (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018). |
| 10.7† | Employment Agreement, dated as of August 30, 2013, by and between Talos Energy Operating Company LLC and William S. Moss III (incorporated by reference to Exhibit 10.14 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018). |

10.8† Separation and Release Agreement by and between the Company and Robert D. Abendschein, effective December 26, 2023 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 29, 2023).

10.9† Talos Energy Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).

10.10† Talos Energy Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).

10.11 Contract for the Exploration and Extraction of Hydrocarbons under Production Sharing Modality (Contract Area 7), dated as of September 4, 2015, by and among the National Hydrocarbons Commission, Sierra O&G Exploración y Producción, S. de R.L. de C.V., Talos Energy Offshore México 7, S. de R.L. de C.V. and Premier Oil Exploration and Production Mexico, S.A. de C.V. (incorporated by reference to Exhibit 10.9 to Talos Energy Inc.'s Amendment No. 4 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on April 4, 2018).

10.12†* Form of Indemnification Agreement (Directors and Officers).

10.13† Form of Restricted Stock Unit Grant Notice and Restricted Stock Agreement (Directors) (incorporated by reference to Exhibit 10.20 to Talos Energy Inc.'s Form 10-Q filed with the SEC on August 9, 2018).

10.14† Form of Talos Energy Inc. Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).

10.15† Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.32 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018)

10.16† Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).

10.17† Form of Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).

10.18† Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on November 3, 2021).

10.19† Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).

10.20† Form of Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).

10.21† Form of Performance Share Unit Cancellation and Release Agreement (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).

10.22† Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).

10.23† Form of Participation Agreement pursuant to Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on October 26, 2020).

10.24† Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.5 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 9, 2023).

| | |
|---|---|
| 10.25 | Joinder, First Amendment to Credit Agreement, and Borrowing Base Reaffirmation Agreement, dated as of July 3, 2019, by and among Talos Energy Inc., as holdings, Talos Production LLC, as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on July 10, 2019). |
| 10.26 | Joinder, Commitment Increase Agreement, Second Amendment to Credit Agreement, Borrowing Base Redetermination Agreement, and Amendment to Other Credit Documents, dated as of December 10, 2019, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019). |
| 10.27 | Third Amendment to Credit Agreement and Borrowing Base Redetermination Agreement, dated as of June 19, 2020, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on June 25, 2020). |
| 10.28 | Borrowing Base Redetermination Agreement and Sixth Amendment to Credit Agreement, dated as of June 22, 2021, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on June 23, 2021). |
| 10.29 | Incremental Agreement, Borrowing Base Redetermination Agreement and Seventh Amendment to Credit Agreement, dated as of December 21, 2021, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.45 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 25, 2022). |
| 10.30 | Borrowing Base Redetermination Agreement and Eighth Amendment to Credit Agreement, dated as of May 4, 2022, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on August 05, 2022). |
| 10.31 | Incremental Agreement of Increasing Lenders, dated as of May 4, 2022, by and among DNB Capital LLC and Mizuho Bank, Ltd, as increasing lender, Talos Production Inc., as borrower, Talos Energy Inc., as holdings, JPMorgan Chase Bank, N.A., as administrative agent, swingline lender and issuing bank and Natixis, New York Branch, as issuing bank.(incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on August 05, 2022). |
| 10.32 | Incremental Agreement and Ninth Amendment to Credit Agreement, dated as of December 23, 2022, among Talos Energy Inc., Talos Production Inc., each other Credit Party, JPMorgan Chase Bank, N.A., as Administrative Agent, each Issuing Bank, the Swingline Lender and each of the Lenders (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 27, 2022). |
| 10.33* | Tenth Amendment to Credit Agreement, dated January 13, 2024, by and among Talos Energy Inc., as Holdings and a Guarantor, Talos Production Inc., as the Borrower, the other Guarantors party thereto, JPMorgan Chase, N.A., as the Administrative Agent, and the Lenders party thereto. |
| 10.34# | Form of QuarterNorth Support Agreement, by and among QuarterNorth Energy Inc., Talos Energy Inc. and the other parties thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 16, 2024). |
| 21.1* | List of Subsidiaries of Talos Energy Inc. |
| 22.1* | List of Subsidiary Guarantors and Issuers of Guaranteed Securities. |
| 23.1* | Consent of Ernst & Young LLP. |
| 23.2* | Consent of Netherland, Sewell & Associates, Inc. |
| 24.1* | Powers of Attorney (included on signature pages of this Part IV). |

| | |
|---|---|
| 31.1* | Certification of Chief Executive Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of Chief Financial Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1** | Certification of Chief Executive Officer and Chief Financial Officer of Talos Energy Inc. pursuant to 18 U.S.C. § 1350, as adopted pursuant to the Sarbanes-Oxley Act of 2002. |
| 97.1* | Talos Energy Inc. Executive Compensation Clawback Policy, effective November 15, 2023. |
| 99.1* | Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2023. |
| 101.INS* | Inline XBRL Instance. |
| 101.SCH* | Inline XBRL Taxonomy Extension Schema. |
| 101.CAL* | Inline XBRL Taxonomy Extension Calculation. |
| 101.DEF* | Inline XBRL Taxonomy Extension Definition. |
| 101.LAB* | Inline XBRL Taxonomy Extension Label. |
| 101.PRE* | Inline XBRL Taxonomy Extension Presentation. |
| 104* | Cover Page Interactive Data File – The cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. |

| | |
|---|---|
| * | Filed herewith. |
| ** | Furnished herewith. |
| † | Identifies management contracts and compensatory plans or arrangements. |
| # | Certain schedules, annexes or exhibits have been omitted pursuant to Item 601(a)(5) of Regulation S-K, but will be furnished supplementally to the SEC upon request. |

**Item 16. Form 10-K Summary**

None.

## SIGNATURES

Pursuant to the requirements 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.

TALOS ENERGY INC.

| | | | |
|---|---|---|---|
| Date: | February 28, 2024 | By: | /s/ Sergio L. Maiworm, Jr. |
| | | | Sergio L. Maiworm, Jr. |
| | | | Chief Financial Officer and Senior Vice President |

## POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Timothy S. Duncan and Sergio L. Maiworm, Jr., and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this report, 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, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming that all said attorneys-in-fact and agents, or any of them or their or his or her substitute or 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.

| Signature | Title | Date |
|---|---|---|
| /s/ Timothy S. Duncan<br>Timothy S. Duncan | Chief Executive Officer<br>(Principal Executive Officer, Director) | February 28, 2024 |
| /s/ Sergio L. Maiworm, Jr.<br>Sergio L. Maiworm, Jr. | Chief Financial Officer<br>(Principal Financial Officer, Authorized Signatory) | February 28, 2024 |
| /s/ Gregory Babcock<br>Gregory Babcock | Chief Accounting Officer<br>(Principal Accounting Officer, Authorized Signatory) | February 28, 2024 |
| /s/ Paula R. Glover<br>Paula R. Glover | Director | February 28, 2024 |
| /s/ Neal P. Goldman<br>Neal P. Goldman | Director | February 28, 2024 |
| /s/ John “Brad” Juneau<br>John “Brad” Juneau | Director | February 28, 2024 |
| /s/ Donald R. Kendall, Jr.<br>Donald R. Kendall, Jr. | Director | February 28, 2024 |
| /s/ Richard Sherrill<br>Richard Sherrill | Director | February 28, 2024 |
| /s/ Charles M. Sledge<br>Charles M. Sledge | Director | February 28, 2024 |
| /s/ Shandell Szabo<br>Shandell Szabo | Director | February 28, 2024 |

**Index to Consolidated Financial Statements**

## Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Talos Energy Inc.

### Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Talos Energy Inc. (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and the financial statement schedule listed in Item 15(a) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with 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, 2023, 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 28, 2024 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 audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

### Critical Audit Matter

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of the critical audit matters 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 matters or on the accounts or disclosures to which it relates.

| | ***Depreciation, depletion and amortization of proved oil and gas properties.*** |
|---|---|
| *Description of the Matter* | As described in Note 2 to the consolidated financial statements, the Company follows the full cost method of accounting for its oil and gas properties. Depreciation, depletion and amortization ("DD&A") of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal reservoir engineers.<br><br>Proved oil and gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection and evaluation of inputs, including historical production, future oil and gas price assumptions, future operating and capital costs assumptions, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to audit the proved oil and gas reserve estimates prepared by the Company's internal reservoir engineers for all properties as of December 31, 2023.<br><br>Auditing the Company's DD&A expense calculation is complex because of the use of the work of the internal reservoir engineers and independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and 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, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves.<br><br>Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates. On a sample basis, we tested the completeness and accuracy of the financial data used in the estimation of proved oil and gas reserves by agreeing significant inputs to source documentation, where available, and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic and lookback procedures on select inputs into the oil and gas reserve estimate. Finally, we tested that the DD&A expense calculations are based on the appropriate proved oil and gas reserve balances from the Company's reserve report. |
| | ***Evaluation of the fair value measurement of oil and gas properties acquired in the EnVen Energy Corporation business combination*** |
| *Description of the Matter* | As described in Note 3 to the consolidated financial statements, the Company executed a merger agreement to acquire EnVen Energy Corporation for net consideration of approximately $1.0 billion. The transaction was accounted for as a business combination.<br><br>The Company applied a discounted cash flow method to estimate the fair value of the proved and unproved oil and gas properties acquired. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Significant inputs to the valuation of proved and unproved oil and gas properties include estimates of future oil and gas price assumption and production profiles of reserve estimates, reserve category risk adjustment factors and discount rate using a market-based weighted average cost of capital.<br><br>Auditing the Company's determination of the fair value of the proved and unproved oil and gas properties acquired was complex due to the significant estimation required by management of reserves associated with the acquired assets and the sensitivity of the significant assumptions used in determining the fair value. In evaluating the reasonableness of management's estimates and assumptions used, the audit testing procedures performed required a high degree of auditor judgment and additional effort, including involving internal specialists. |
| *How We Addressed the Matter in Our Audit* | We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's internal controls over its process to estimate the fair value of the acquired proved and unproved oil and gas properties, including management's review of the significant assumptions used as inputs to the fair value calculations.<br><br>To test the estimated fair value of the acquired proved and unproved oil and gas properties, our audit procedures included, among others, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data supporting the significant assumptions. For example, we compared and assessed certain significant assumptions to current industry or third-party data for reasonableness.<br><br>We also performed sensitivity analyses of significant assumptions, to evaluate the extent of their impact to the fair value calculation. In addition, we involved our valuation specialists to assist with certain significant assumptions included in the fair value estimate. Furthermore, we evaluated the professional qualifications and objectivity of the third-party valuation specialist engaged by the Company to prepare the fair value of the acquired proved and unproved oil and gas properties. |
| | ***Asset Retirement Obligations*** |
| *Description of the Matter* | As described in Note 2 and 9 of the consolidated financial statements, the Company records a liability for the Asset Retirement Obligation at fair value in the period in which it is incurred. The retirement obligations are periodically adjusted to reflect changes in the expected cash flows resulting from revisions to the estimates of either the timing or amount of the retirement costs. Due to the complexity involved in estimating the expected cash outflows, management used a specialist to estimate the expected cash outflows for the Company's asset retirement obligation as of December 31, 2023. |

| | |
|---|---|
| | Auditing management's accounting for retirement obligations was especially challenging, as significant judgment is required by the Company in determining the obligation. The significant judgment was primarily related to the inherent estimation uncertainty relating to the expected cash outflows extent of future asset retirement activities and the ultimate productive life of the properties. |
| *How We Addressed the Matter in Our Audit* | We obtained an understanding, evaluated the design, and tested the operating effectiveness of the controls over the Company's accounting for asset retirement obligation, including the controls over management's review of the significant assumptions described above.<br><br>To test the asset retirement obligation, among other procedures, we evaluated the methodology, tested the significant assumptions described above and tested the completeness and accuracy of the underlying data used by the Company in estimating the expected cashflows. To assess the estimates of asset retirement activities and cash flows, we evaluated significant changes from the prior estimate, verified consistency between the timing of asset retirement activities and projected productive life of the properties, verified cost rates against third-party information or internal cost records and recalculated management's estimate. We involved our asset retirement specialists to assist in our evaluation of the expected cash outflows for asset retirement obligation. |

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2010.

Houston, Texas
February 28, 2024

## Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Talos Energy Inc.

**Opinion on Internal Control Over Financial Reporting**

We have audited Talos Energy Inc.'s internal control over financial reporting as of December 31, 2023, 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, Talos Energy Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, 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 consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and the financial statement schedule listed in Item 15(a) (collectively referred to as the consolidated financial statements") and our report dated February 28, 2024 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 Report of Management 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

Houston, Texas
February 28, 2024

**TALOS ENERGY INC.**
**CONSOLIDATED BALANCE SHEETS**
**(In thousands, except share amounts)**

| | Year Ended December 31, 2023 | 2022 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 33,637 | $ 44,145 |
| Accounts receivable: | | |
| Trade, net | 178,977 | 150,598 |
| Joint interest, net | 79,337 | 54,697 |
| Other, net | 19,296 | 6,684 |
| Assets from price risk management activities | 36,152 | 25,029 |
| Prepaid assets | 64,387 | 84,759 |
| Other current assets | 10,389 | 1,917 |
| Total current assets | 422,175 | 367,829 |
| Property and equipment: | | |
| Proved properties | 7,906,295 | 5,964,340 |
| Unproved properties, not subject to amortization | 268,315 | 154,783 |
| Other property and equipment | 34,027 | 30,691 |
| Total property and equipment | 8,208,637 | 6,149,814 |
| Accumulated depreciation, depletion and amortization | (4,168,328) | (3,506,539) |
| Total property and equipment, net | 4,040,309 | 2,643,275 |
| Other long-term assets: | | |
| Restricted cash | 102,362 | — |
| Assets from price risk management activities | 17,551 | 7,854 |
| Equity method investments | 146,049 | 1,745 |
| Other well equipment | 54,277 | 25,541 |
| Notes receivable, net | 16,207 | — |
| Operating lease assets | 11,418 | 5,903 |
| Other assets | 5,961 | 6,479 |
| **Total assets** | $ 4,816,309 | $ 3,058,626 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 84,193 | $ 128,174 |
| Accrued liabilities | 227,690 | 219,769 |
| Accrued royalties | 55,051 | 52,215 |
| Current portion of long-term debt | 33,060 | — |
| Current portion of asset retirement obligations | 77,581 | 39,888 |
| Liabilities from price risk management activities | 7,305 | 68,370 |
| Accrued interest payable | 42,300 | 36,340 |
| Current portion of operating lease liabilities | 2,666 | 1,943 |
| Other current liabilities | 48,769 | 60,359 |
| Total current liabilities | 578,615 | 607,058 |
| Long-term liabilities: | | |
| Long-term debt | 992,614 | 585,340 |
| Asset retirement obligations | 819,645 | 501,773 |
| Liabilities from price risk management activities | 795 | 7,872 |
| Operating lease liabilities | 18,211 | 14,855 |
| Other long-term liabilities | 251,278 | 176,152 |
| Total liabilities | 2,661,158 | 1,893,050 |
| Commitments and contingencies (Note 14) | | |
| Stockholders' equity: | | |
| Preferred stock; $0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of December 31, 2023 and 2022, respectively | — | — |
| Common stock; $0.01 par value; 270,000,000 shares authorized; 127,480,361 and 82,570,328 shares issued as of December 31, 2023 and 2022, respectively | 1,275 | 826 |
| Additional paid-in capital | 2,549,097 | 1,699,799 |
| Accumulated deficit | (347,717) | (535,049) |
| Treasury stock, at cost; 3,400,000 and zero shares as of December 31, 2023 and 2022, respectively | (47,504) | — |
| Total stockholders' equity | 2,155,151 | 1,165,576 |
| **Total liabilities and stockholders' equity** | $ 4,816,309 | $ 3,058,626 |

See accompanying notes.

## TALOS ENERGY INC.
## CONSOLIDATED STATEMENTS OF OPERATIONS
## (In thousands, except share amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Revenues: | | | |
| Oil | $ 1,357,732 | $ 1,365,148 | $ 1,064,161 |
| Natural gas | 68,034 | 227,306 | 130,616 |
| NGL | 32,120 | 59,526 | 49,763 |
| Total revenues | 1,457,886 | 1,651,980 | 1,244,540 |
| Operating expenses: | | | |
| Lease operating expense | 389,621 | 308,092 | 283,601 |
| Production taxes | 2,451 | 3,488 | 3,363 |
| Depreciation, depletion and amortization | 663,534 | 414,630 | 395,994 |
| Write-down of oil and natural gas properties | — | — | 18,123 |
| Accretion expense | 86,152 | 55,995 | 58,129 |
| General and administrative expense | 158,493 | 99,754 | 78,677 |
| Other operating (income) expense | (52,155) | 33,902 | 32,037 |
| Total operating expenses | 1,248,096 | 915,861 | 869,924 |
| Operating income (expense) | 209,790 | 736,119 | 374,616 |
| Interest expense | (173,145) | (125,498) | (133,138) |
| Price risk management activities income (expense) | 80,928 | (272,191) | (419,077) |
| Equity method investment income (expense) | (3,209) | 14,222 | — |
| Other income (expense) | 12,371 | 31,800 | (6,988) |
| Net income (loss) before income taxes | 126,735 | 384,452 | (184,587) |
| Income tax benefit (expense) | 60,597 | (2,537) | 1,635 |
| **Net income (loss)** | $ 187,332 | $ 381,915 | $ (182,952) |
| | | | |
| Net income (loss) per common share: | | | |
| Basic | $ 1.56 | $ 4.63 | $ (2.24) |
| Diluted | $ 1.55 | $ 4.56 | $ (2.24) |
| Weighted average common shares outstanding: | | | |
| Basic | 119,894 | 82,454 | 81,769 |
| Diluted | 120,752 | 83,683 | 81,769 |

See accompanying notes.

## TALOS ENERGY INC.
## CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
## (In thousands, except share amounts)

| | Common Stock | | Additional Paid-In Capital | Accumulated Deficit | Treasury Stock | | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|
| | Shares Issued | Par Value | | | Shares | Amount | |
| Balance at December 31, 2020 | 81,279,989 | $ 813 | $ 1,659,800 | $ (734,012) | — | $ — | $ 926,601 |
| Equity-based compensation | — | — | 20,165 | — | — | — | 20,165 |
| Equity-based compensation tax withholdings | — | — | (3,161) | — | — | — | (3,161) |
| Equity-based compensation stock issuances | 601,488 | 6 | (6) | — | — | — | — |
| Net income (loss) | — | — | — | (182,952) | — | — | (182,952) |
| Balance at December 31, 2021 | 81,881,477 | 819 | 1,676,798 | (916,964) | — | — | 760,653 |
| Equity-based compensation | — | — | 27,611 | — | — | — | 27,611 |
| Equity-based compensation tax withholdings | — | — | (4,603) | — | — | — | (4,603) |
| Equity-based compensation stock issuances | 688,851 | 7 | (7) | — | — | — | — |
| Net income (loss) | — | — | — | 381,915 | — | — | 381,915 |
| Balance at December 31, 2022 | 82,570,328 | 826 | 1,699,799 | (535,049) | — | — | 1,165,576 |
| Equity-based compensation | — | — | 25,008 | — | — | — | 25,008 |
| Equity-based compensation tax withholdings | — | — | (7,459) | — | — | — | (7,459) |
| Equity-based compensation stock issuances | 1,110,143 | 11 | (11) | — | — | — | — |
| Issuance of common stock for acquisition (Note 3) | 43,799,890 | 438 | 831,760 | — | — | — | 832,198 |
| Purchase of treasury stock | — | — | — | — | 3,400,000 | (47,504) | (47,504) |
| Net income (loss) | — | — | — | 187,332 | — | — | 187,332 |
| Balance at December 31, 2023 | 127,480,361 | $ 1,275 | $ 2,549,097 | $ (347,717) | 3,400,000 | $ (47,504) | $ 2,155,151 |

See accompanying notes.

## TALOS ENERGY INC.
## CONSOLIDATED STATEMENTS OF CASH FLOWS
## (In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ 187,332 | $ 381,915 | $ (182,952) |
| Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities | | | |
| Depreciation, depletion, amortization and accretion expense | 749,686 | 470,625 | 454,123 |
| Write-down of oil and natural gas properties and other well equipment | — | — | 23,729 |
| Amortization of discount, premium and deferred financing costs | 15,039 | 14,379 | 13,382 |
| Equity-based compensation expense | 12,953 | 15,953 | 10,992 |
| Price risk management activities (income) expense | (80,928) | 272,191 | 419,077 |
| Net cash received (paid) on settled derivative instruments | (9,457) | (425,559) | (290,164) |
| Equity method investment (income) expense | 3,209 | (14,222) | — |
| Loss (gain) on extinguishment of debt | — | 1,569 | 13,225 |
| Settlement of asset retirement obligations | (86,615) | (69,596) | (67,988) |
| Gain (loss) on sale of assets | (66,115) | 303 | (687) |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | 20,352 | 14,927 | (35,396) |
| Other current assets | 7,066 | (36,545) | (18,901) |
| Accounts payable | (60,401) | 24,258 | (6,261) |
| Other current liabilities | (96,960) | 73,531 | 64,800 |
| Other non-current assets and liabilities, net | (76,092) | (13,990) | 14,409 |
| Net cash provided by (used in) operating activities | 519,069 | 709,739 | 411,388 |
| Cash flows from investing activities: | | | |
| Exploration, development and other capital expenditures | (561,434) | (323,164) | (293,331) |
| Proceeds from (cash paid for) acquisitions, net of cash acquired | 17,617 | (3,500) | (5,399) |
| Proceeds from (cash paid for) sale of property and equipment, net | 73,004 | 1,937 | 4,983 |
| Contributions to equity method investees | (29,447) | (2,250) | — |
| Investment in intangible assets | (12,366) | — | — |
| Proceeds from sale of equity method investment | — | 15,000 | — |
| Net cash provided by (used in) investing activities | (512,626) | (311,977) | (293,747) |
| Cash flows from financing activities: | | | |
| Issuance of senior notes | — | — | 600,500 |
| Redemption of senior notes | (30,000) | (18,184) | (356,803) |
| Proceeds from Bank Credit Facility | 825,000 | 85,000 | 100,000 |
| Repayment of Bank Credit Facility | (625,000) | (460,000) | (365,000) |
| Deferred financing costs | (11,775) | (189) | (27,833) |
| Other deferred payments | (1,545) | — | (7,921) |
| Payments of finance lease | (16,306) | (25,493) | (21,804) |
| Purchase of treasury stock | (47,504) | — | — |
| Employee stock awards tax withholdings | (7,459) | (4,603) | (3,161) |
| Net cash provided by (used in) financing activities | 85,411 | (423,469) | (82,022) |
| | | | |
| Net increase (decrease) in cash, cash equivalents and restricted cash | 91,854 | (25,707) | 35,619 |
| Cash, cash equivalents and restricted cash: | | | |
| Balance, beginning of period | 44,145 | 69,852 | 34,233 |
| Balance, end of period | $ 135,999 | $ 44,145 | $ 69,852 |
| | | | |
| Supplemental non-cash transactions: | | | |
| Capital expenditures included in accounts payable and accrued liabilities | $ 114,972 | $ 105,773 | $ 45,761 |
| Supplemental cash flow information: | | | |
| Interest paid, net of amounts capitalized | $ 130,313 | $ 91,809 | $ 68,891 |

See accompanying notes.

## Note 1 — Organization, Nature of Business and Basis of Presentation

### Organization and Nature of Business

Talos Energy Inc. (the "Parent Company") is a Delaware corporation originally incorporated on November 14, 2017. The Parent Company conducts all business operations through its operating subsidiaries, owns no operating assets and has no material operations, cash flows or liabilities independent of its subsidiaries. The Parent Company's common stock is traded on The New York Stock Exchange under the ticker symbol "TALO."

The Parent Company (including its subsidiaries, collectively "Talos" or the "Company") is a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through its operations, currently in the United States ("U.S.") and offshore Mexico both through upstream oil and gas exploration and production and the development of low carbon solutions opportunities. The Company leverages decades of technical and offshore operational expertise in the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. The Company is also utilizing its expertise to develop CCS projects to help reduce industrial emissions along the coast of the U.S. Gulf of Mexico.

### Basis of Presentation and Consolidation

The Consolidated Financial Statements have been prepared in accordance with GAAP and include the accounts of the Parent Company and entities in which the Parent Company holds a controlling financial interest. Both majority-owned subsidiaries and any variable interest entity in which the Parent Company is the primary beneficiary are consolidated. All intercompany transactions have been eliminated. All adjustments are of a normal, recurring nature and are necessary to fairly present the financial position, results of operations and cash flows for the periods reflected herein.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

### Segments

The Company has two operating segments: (i) exploration and production of oil, natural gas and NGLs ("Upstream Segment") and (ii) CCS ("CCS Segment"). The Upstream Segment is the Company's only reportable segment. The legal entities included in the CCS Segment have been designated as unrestricted, non-guarantor subsidiaries of the Company for purposes of the Bank Credit Facility (as defined in Note 2 — *Summary of Significant Accounting Policies*) and indenture governing the senior notes. See additional information in Note 15 — *Segment Information.*

### Recently Issued Accounting Standards

***Segment Reporting* —** In November 2023, the Financial Accounting Standards Board ("FASB") issued an update to the required disclosures for segment reporting. The update is intended to improve reportable segment disclosures, primarily through enhanced disclosures about significant segment expenses. The update will require public entities to disclose significant segment expenses that are regularly provided to the chief operating decision maker and included within segment profit and loss. The update is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024 on a retrospective basis. Early adoption is permitted. The Company is currently evaluating the effect of this update on the Company's disclosures.

***Tax Disclosures* —** In December 2023, the FASB issued an update which expands disclosures in an entity's income tax rate reconciliation table and regarding cash taxes paid both in the U.S. and foreign jurisdictions. The update is effective for annual periods beginning after December 15, 2024 on a prospective basis. However, retrospective application in all periods presented is permitted. The Company is currently evaluating the effect of this update on the Company's disclosures.

## Note 2 — Summary of Significant Accounting Policies

### Overview of Significant Accounting Policies

***Cash and Cash Equivalents* —** The Company presents cash as "Cash and cash equivalents" on the Company's Consolidated Balance Sheets. The Company considers all cash, money market funds and highly liquid investments with an original maturity of three months or less as cash and cash equivalents. Cash and cash equivalents are carried at cost, which approximates fair value.

***Accounts Receivable and Allowance for Expected Credit Losses*** — Accounts receivable are stated at the historical carrying amount net of an allowance for expected credit losses. At each reporting period, the recoverability of material receivables is assessed using historical data, current market conditions and reasonable and supported forecasts of future economic conditions to determine their expected collectability. A loss-rate methodology is used to estimate the allowance for expected credit losses to be accrued on material receivables to reflect the net amount to be collected. As of December 31, 2023 and 2022, the Company had allowances of $8.8 million and $10.7 million, respectively, presented net in accounts receivable on the Consolidated Balance Sheets.

***Price Risk Management Activities* —** The Company uses commodity price derivatives to manage fluctuating oil and natural gas market risks. The Company periodically enters into commodity derivative contracts, which may require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes.

Commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded in earnings each period. Realized gains and losses on the settlement of commodity derivatives and changes in their unrealized gains and losses are reported in "Price risk management activities income (expense)" on the Consolidated Statements of Operations. The Company classifies cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of the Company's oil and natural gas operations, they are classified as cash flows from operating activities. The Company does not enter into derivative agreements for trading or other speculative purposes.

The commodity derivative's fair value reflects the Company's best estimate with priority based upon exchange or over-the-counter quotations. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Company then utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Company to make estimations of future prices, price correlation, market volatility and liquidity. The Company's actual results may differ from its estimates, and these differences can be favorable or unfavorable.

***Prepaid Assets* —** Prepaid assets primarily represent prepaid subscriptions, insurance, progress payments for well equipment and deposits with the Office of Natural Resources Revenue ("ONRR"). The progress payments made for well equipment relate to long lead time items which the Company has not taken title to as of period end. The deposits with ONRR represent the Company's estimated federal royalties payable within thirty days of the production date. On a monthly basis, the Company adjusts the deposit based on actual royalty payments remitted to the ONRR.

***Accounting for Oil and Natural Gas Activities* —** The Company follows the full cost method of accounting for oil and natural gas exploration and development activities. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Capitalized costs associated with proved reserves are amortized on a country-by-country basis over the life of the total proved reserves using the unit of production method, computed quarterly. Conversely, capitalized costs associated with unproved properties and related geological and geophysical costs, exploration wells currently drilling and capitalized interest are initially excluded from the amortizable base. The Company transfers unproved property costs into the amortizable base when properties are determined to have proved reserves or when the Company has completed an unproved properties evaluation resulting in an impairment. The Company evaluates each of these unproved properties individually for impairment at least annually. Additionally, the amortizable base includes future development costs, dismantlement, restoration and abandonment costs, net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with specific unproved properties or prospects in which the Company owns a direct interest. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities.

The Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Generally, any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on the Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC Pricing when performing the ceiling test. The Company also holds prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period.

Under the full cost method of accounting for oil and natural gas operations, assets whose costs are currently being depreciated, depleted or amortized are assets in use in the earnings activities of the enterprise and do not qualify for capitalization of interest cost. Investments in unproved properties for which exploration and development activities are in progress and other major development projects that are not being currently depreciated, depleted or amortized are assets qualifying for capitalization of interest costs.

When the Company sells or conveys interests in oil and natural gas properties, the Company reduces its oil and natural gas reserves for the amount attributable to the sold or conveyed interest. The Company treats sales proceeds on non-significant sales as reductions to the cost of the Company's oil and natural gas properties. The Company does not recognize a gain or loss on sales of oil and natural gas properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves.

***Other Property and Equipment —*** Other property and equipment is recorded at cost and consists primarily of leasehold improvements, office furniture and fixtures and computer hardware. Acquisitions and betterments are capitalized; maintenance and repairs are expensed as incurred. Depreciation is provided using the straight-line method over estimated useful lives of three to ten years.

***Restricted Cash —*** Any cash that is legally restricted from use is classified as restricted cash. If the purpose of restricted cash relates to acquiring a long-term asset, liquidating a long-term liability, or is otherwise unavailable for a period longer than one year from the balance sheet date, the restricted cash is included in other long-term assets. Otherwise, restricted cash is included in other current assets in the Consolidated Balance Sheets. The Company acquired funds held in escrow to be used for future plugging and abandonment ("P&A") obligations assumed through the EnVen Acquisition (as defined in Note 3 — *Acquisitions and Divestitures*). These escrow accounts required deposits of approximately $100.0 million, which was fully funded by EnVen (as defined in Note 3 — *Acquisitions and Divestitures*) prior to the consummation of the acquisition. This is reflected as "Restricted Cash" within "Other long-term assets" on the Consolidated Balance Sheets.

***Equity Method Investments —*** The Company generally accounts for investments under the equity method of accounting when it exercises significant influence over the entity's operating and financial policies but does not hold a controlling financial interest in the entity. The voting percentage that is presumed to provide an investor with the required level of influence necessary to apply the equity method of accounting varies depending on the nature of the investee. For investments in common stock, in-substance common stock, a limited liability company or partnership that does not maintain specific ownership accounts for each investor, a voting percentage of 20% or more is generally presumed to demonstrate significant influence. For investments in a limited partnership or unincorporated joint venture and a limited liability company or partnership that maintains a specific ownership account for each investor, a voting percentage of 3-5% or more is generally presumed to demonstrate significant influence. Equity method accounting for interests in limited partnerships is generally appropriate unless the interest is so minor that the investor has virtually no influence (less than 3%).

In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for the Company's proportionate share of earnings, losses, contributions and distributions. Investments accounted for using the equity method are reflected as "Equity method investments" on the Consolidated Balance Sheets. The equity in earnings of an investee is reflected in "Equity method investment income (expense)" on the Consolidated Statement of Operations. The gain or loss from the full or partial sale of an equity method investment is presented in the same line item in which the Company reports the equity in earnings of the investee.

The Company assesses equity method investments for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred if the loss is deemed to be other-than-temporary. When the loss is deemed to be other-than-temporary, the carrying value of the equity method investment is written down to fair value. The impairment charge is included as a component of the Company's share of the earning or losses of the investee. No impairment charges have been recorded during the years ended December 31, 2023, 2022 and 2021.

***Other Well Equipment*** — Other well equipment primarily represents the cost of equipment to be used in the Company's oil and natural gas drilling and development activities such as drilling pipe, tubulars and certain wellhead equipment. When well equipment is supplied to wells, the cost is capitalized in oil and gas properties, and if such property is jointly owned, the proportionate costs will be reimbursed by third party participants.

***Notes Receivable, net —*** The Company holds two notes receivable with an aggregate face value of $66.2 million acquired by the Company as part of the EnVen Acquisition (as defined herein), which consist of commitments from the sellers of oil and natural gas properties related to the costs associated with P&A obligations (the "P&A Notes Receivable"). The P&A Notes Receivable are recorded at a discounted value, being accreted to their principal amounts and presented as such, net of related cumulative estimated credit losses, on the accompanying Consolidated Balance Sheets. The Company estimates the current expected credit losses related to its P&A Notes Receivable using the probability of default method based on the long-term credit ratings of the counterparties of the notes, which are currently considered "investment grade."

***Leases —*** At inception, contracts are reviewed to determine whether the agreement contains a lease. To the extent an arrangement is determined to include a lease, it is classified as either an operating or a finance lease, which dictates the pattern of expense recognition in the income statement. Operating leases are reflected as "Operating lease assets," "Current portion of operating lease liabilities" and "Operating lease liabilities" on the Consolidated Balance Sheets. Finance leases are included in "Property and equipment," "Other current liabilities" and "Other long-term liabilities" on the Consolidated Balance Sheets.

A right-of-use ("ROU") asset representing our right to use an underlying asset for the lease term and a lease liability representing our obligation to make lease payments arising from the lease are recognized on the Consolidated Balance Sheets for all leases, regardless of classification. The ROU asset is initially measured as the present value of the lease liability adjusted for any payments made prior to lease commencement, including any initial direct costs incurred and incentives received. Lease liabilities are initially measured at the present value of future minimum lease payments, excluding variable lease payments, over the lease term. As most of our leases do not provide an implicit rate, the Company generally uses an incremental borrowing rate based on the estimated rate of interest for collateralized borrowing over a similar term of the lease payments at commencement date.

The Company has elected to account for lease and non-lease components in its contracts as a single lease component for all asset classes except for our leased floating production vessel class. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. The Company has elected, as an accounting policy, not to record leases with terms of twelve months or less (i.e., short-term) on the Consolidated Balance Sheets. See Note 5 — *Leases* for additional information.

***Debt Issuance Costs —*** The Company presents debt issuance costs associated with revolving line-of-credit arrangements as a reduction of the carrying value of long-term debt.

***Asset Retirement Obligations —*** The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as "Accretion expense" on the Company's Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for asset retirement obligations, the Company recognizes the difference as an adjustment to proved properties.

***Decommissioning Obligations —*** Certain counterparties in divestiture transactions or third parties in existing leases that have filed for bankruptcy protection or undergone associated reorganizations may not be able to perform required abandonment obligations. The Company may be held jointly and severally liable for the decommissioning of various facilities and related wells. The Company accrues losses associated with decommissioning obligations when such losses are probable and reasonably estimable. When there is a range of possible outcomes, the amount accrued is the most likely outcome within the range. If no single outcome within the range is more likely than the others, the minimum amount in the range is accrued. These accruals may be adjusted as additional information becomes available. In addition, when decommissioning obligations are reasonably possible, the Company discloses an estimate for a possible loss or range of loss (or a statement that such an estimate cannot be reasonably made). See Note 14 — *Commitments & Contingencies* for additional information.

***Share-Based Compensation —*** Certain of the Company's employees participate in its equity-based compensation plan. The Company measures all employee equity-based compensation awards at fair value on the date awards are granted to its employees.

The fair value of the stock-based awards is determined at the date of grant and is not remeasured for awards classified as equity unless the award is modified. Liability classified awards are remeasured at each reporting period. The Company records share-based compensation, net of actual forfeitures, for the restricted stock units ("RSUs") and performance share units ("PSUs") in "General and administrative expense" on the Consolidated Statements of Operations, net of amounts capitalized to oil and gas properties. See Note 10 — *Employee Benefits Plans and Share-Based Compensation* for additional information.

***RSUs —*** Share-based compensation is based on the market price of the Company's common stock on the grant date and recognized over the requisite service period using the straight-line method.

***PSUs with Market Based Conditions*** **—** Share-based compensation is based on the grant date fair value determined using a Monte Carlo valuation model for awards with a market condition and recognized over the requisite service period using the straight-line method. Estimates used in the Monte Carlo valuation model are considered highly-complex and subjective. The number of shares of common stock issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on the Company's total shareholder return ("TSR"). Share-based compensation related to PSUs with a market condition are recognized as the requisite service period is fulfilled, even if the market condition is not achieved.

***PSUs with Performance Based Conditions*** **—** Share-based compensation is based on the market price of the Company's common stock on the grant date and recognized over the requisite service period using the straight-line method for awards with a performance condition. The Company recognizes compensation cost for awards with performance conditions if and when the Company concludes that it is probable that the performance condition will be achieved. The Company reassesses the probability of vesting at each reporting period for awards with performance conditions and adjusts compensation cost based on its probability assessment. The Company recognizes a cumulative catch-up adjustment for such changes in its probability assessment in subsequent reporting periods, using the grant date fair value of the award whose terms reflect the updated probable performance condition (which could be either a reversal or increase in expense). The number of shares of common stock issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on a metric associated with the Company's own operations or activities.

***Revenue Recognition*** **—** Revenues are recorded based from the sale of oil, natural gas and NGL quantities sold to purchasers. The Company records revenues from the sale of oil, natural gas and NGLs based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred. The Company recognizes transportation costs as a component of lease operating expense when it is the shipper of the product. Each unit of product typically represents a separate performance obligation, therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

***Production Handling Fees*** **—** The Company presents certain reimbursements for costs from certain third parties as a reduction of "Lease operating expense" on the Consolidated Statements of Operations.

***ONRR Federal Royalty Refund*** **—** Included within "Other operating (income) expense" on the Consolidated Statements of Operations is income from the Company's multi-year federal royalty refund claim from the ONRR. The Company records income when a refund is filed and its collection is reasonably assured.

***Income Taxes*** **—** The Company records current income taxes based on estimates of current taxable income and provides for deferred income taxes to reflect estimated future income tax payments and receipts. The impact to changes in tax laws are recorded in the period the change is enacted. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. The Company classifies all deferred tax assets and liabilities, along with any related valuation allowance, as long-term on the Consolidated Balance Sheets.

The realization of deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. The Company reduces deferred tax assets by a valuation allowance when, based on estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The deferred tax asset estimates are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating the Company's valuation allowances, the Company considers cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in carryback years, tax planning strategies and future taxable income for each of its taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to the Company's valuation allowances could materially impact its results of operations.

The Company's policy is to classify interest and penalties associated with underpayment of income taxes as "Interest expense" and "General and administrative expense" on the Consolidated Statements of Operations, respectively.

***Income (Loss) Per Share*** **—** Basic net income per common share ("EPS") is computed by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted EPS includes the impact of RSUs, PSUs and outstanding warrants. See Note 12 — *Income (Loss) Per Share* for additional information.

***Fair Value Measure of Financial Instruments*** **—** Financial instruments generally consist of cash and cash equivalents, accounts receivable, commodity derivatives, accounts payable and debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments.

Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify fair value is an exit price, presenting the amount that would be received to sell an asset or paid to transfer a liability, in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

- ***Level 1 –*** Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- ***Level 2 –*** Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement.
- ***Level 3 –*** Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

- ***Market Approach –*** Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
- ***Cost Approach –*** Amount that would be required to replace the service capacity of an asset (replacement cost).
- ***Income Approach –*** Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

***Variable Interest Entities —*** Upon inception of a contractual agreement, the Parent Company performs an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a variable interest Entity (“VIE”). The Parent Company assesses all aspects of its interests in an entity and uses judgment when determining if it is the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reassessment of the primary beneficiary conclusion is conducted when there are changes in the facts and circumstances related to a VIE. See Note 7 — *Equity Method Investments* for additional information.

**Concentration of Credit Risk**

Consisting principally of cash and cash equivalents, accounts receivable and commodity derivatives, the Company is subject to concentrated financial instruments credit risk.

Cash and cash equivalents balances are maintained in financial institutions, which at times, exceed federally insured limits. The Company monitors the financial condition of these institutions and has not experienced losses on these accounts.

Commodity derivatives are entered into with registered swap dealers, all of which participate in the Company’s senior reserve-based revolving credit facility (the “Bank Credit Facility”). The Company monitors the financial condition of these institutions and has not experienced losses due to counterparty default on these instruments.

The Company markets the majority of its oil and natural gas production, and substantially all of its revenues are attributable to the U.S. The majority of the Company’s oil, natural gas and NGL production is sold to customers under short-term (less than 12 months) contracts at market-based prices. The Company’s customers consist primarily of major oil and natural gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. The Company performs ongoing credit evaluations of its customers and provide allowances for probable credit losses when necessary.

The percent of consolidated revenue of major customers, those whose total represented 10% or more of the Company's oil, natural gas and NGL revenues, was as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Shell Trading (US) Company | 54% | 44% | 45% |
| Valero Energy Corporation | 21% | 23% | ** |
| Chevron Products Company | ** | 11% | 29% |

** Less than 10%

The loss of a major customer could have material adverse effect on the Company in the short term. However, the Company believes it would be able to obtain other customers to market its oil, natural gas and NGL production.

**Cash, Cash Equivalents and Restricted Cash**

The following table provides a reconciliation of the amount of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheets to the total of the same such amounts shown in the Consolidated Statement of Cash Flows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Cash and cash equivalents | $ 33,637 | $ 44,145 |
| Restricted cash included in Other long-term assets | 102,362 | — |
| Total cash, cash equivalent and restricted cash | $ 135,999 | $ 44,145 |

## Note 3 — Acquisitions and Divestitures

**Business Combinations**

Acquisitions qualifying as business combinations are accounted for under the acquisition method of accounting, which requires, among other items, that assets acquired and liabilities assumed be recognized on the Consolidated Balance Sheets at their fair values as of the acquisition date.

***EnVen Acquisition —*** On September 21, 2022, the Company executed a merger agreement to acquire EnVen Energy Corporation ("EnVen"), a private operator in the Deepwater U.S. Gulf of Mexico (the "EnVen Acquisition," and such agreement, the "EnVen Merger Agreement"). On February 13, 2023, the Company completed the EnVen Acquisition for consideration consisting of (i) $207.3 million in cash, (ii) 43.8 million shares of the Company's common stock valued at $832.2 million and (iii) the effective settlement of an accounts receivable balance of $8.4 million. No gain or loss was recognized on settlement as the payable was effectively settled at the recorded amount. The cash payment was partially funded with borrowings under the Bank Credit Facility.

The following table summarizes the purchase price (in thousands except share and per share data):

| | |
|---|---|
| Talos common stock | 43,799,890 |
| Talos common stock price per share(1) | $ 19.00 |
| Common stock value | $ 832,198 |
| | |
| Cash consideration | $ 207,313 |
| Settlement of preexisting relationship | $ 8,388 |
| | |
| Total purchase price | $ 1,047,899 |

(1) Represents the closing price of the Company's common stock on February 13, 2023, the date of the closing of the EnVen Acquisition.

The following table presents the final allocation of the purchase price to the assets acquired and liabilities assumed based on their fair values on February 13, 2023 (in thousands):

| | | |
|---|---|---|
| Current assets | $ | 243,571 |
| Property and equipment | | 1,455,347 |
| Other long-term assets: | | |
| Restricted cash | | 100,753 |
| Notes receivable, net | | 14,844 |
| Other long-term assets | | 48,899 |
| Current liabilities: | | |
| Current portion of long-term debt | | (33,234) |
| Current portion of asset retirement obligations | | (7,079) |
| Other current liabilities | | (124,347) |
| Long-term liabilities: | | |
| Long-term debt | | (233,836) |
| Asset retirement obligations | | (251,779) |
| Deferred tax liabilities | | (150,264) |
| Other long-term liabilities | | (14,976) |
| Allocated purchase price | $ | 1,047,899 |

The fair values determined for accounts receivable, accounts payable and other current assets and most current liabilities were equivalent to the carrying value due to their short-term nature. Assumed debt was valued based on observable market prices.

The fair value of proved oil and natural gas properties as of the acquisition date is based on estimated proved oil, natural gas and NGL reserves and related discounted future net cash flows incorporating market participant assumptions. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices, and a weighted average cost of capital discount rate. When estimating the fair value of proved and unproved properties, additional risk adjustments were applied to proved developed non-producing, proved undeveloped, probable and possible reserves to reflect the relative uncertainty of each reserve class. These inputs are classified as Level 3 unobservable inputs, including the underlying commodity price assumptions which are based on the five-year NYMEX forward strip prices, escalated for inflation thereafter, and adjusted for price differentials.

The fair value of asset retirement obligations is determined by calculating the present value of estimated future cash flows related to the liabilities. The Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate.

The Company incurred approximately $21.8 million of acquisition-related costs in connection with the EnVen Acquisition exclusive of severance expense, of which $12.8 million was recognized during the year ended December 31, 2023 and $9.0 million was recognized during the year ended December 31, 2022 and reflected in general and administrative expense on the Consolidated Statements of Operations. Additionally, the Company incurred $25.3 million in severance expense in connection with the EnVen Acquisition for the year ended December 31, 2023. See Note 10 — *Employee Benefit Plans and Share-Based Compensation* for additional discussion.

The following table presents revenue and net income (loss) attributable to the EnVen Acquisition for the period from February 13, 2023 to December 31, 2023 (in thousands):

| | Year Ended December 31, 2023 | |
|---|---|---|
| Revenue | $ | 423,624 |
| Net income (loss) | $ | 85,622 |

***Pro Forma Financial Information (Unaudited) —*** The following supplemental pro forma financial information (in thousands, except per common share amounts), presents the consolidated results of operations for the years ended December 31, 2023 and 2022 as if the EnVen Acquisition had occurred on January 1, 2022. The unaudited pro forma information was derived from historical statements of operations of the Company and EnVen adjusted to include (i) depletion expense applied to the adjusted basis of the oil and natural gas properties acquired, (ii) interest expense to reflect borrowings under the Bank Credit Facility and to adjust the amortization of the premium of the 11.75% Notes (as defined in Note 8 — *Debt*), (iii) general and administrative expense adjusted for transaction related costs incurred (including severance), (iv) other income (expense) to adjust the accretion of the discount on the P&A Notes Receivable and (v) weighted average basic and diluted shares of common stock outstanding from the issuance of 43.8 million shares of common stock to EnVen. Supplemental pro forma earnings for the year ended December 31, 2022 were adjusted to include $65.1 million of general and administrative expenses, of which $16.3 million were incurred during the year ended December 31, 2022. Supplemental pro forma earnings for the year ended December 31, 2023 were adjusted to exclude $65.1 million of general and administrative expenses. This information does not purport to be indicative of results of operations that would have occurred had the EnVen Acquisition occurred on January 1, 2022, nor is such information indicative of any expected future results of operations (in thousands, except for the per share data).

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Revenue | $ 1,509,929 | $ 2,355,215 |
| Net income (loss) | $ 217,537 | $ 425,995 |
| Basic net income (loss) per common share | $ 1.74 | $ 3.37 |
| Diluted net income (loss) per common share | $ 1.73 | $ 3.34 |

**Subsequent Event**

***QuarterNorth Acquisition —*** On January 13, 2024, the Company executed a merger agreement to acquire QuarterNorth Energy Inc. ("QuarterNorth," and such acquisition, the "QuarterNorth Acquisition"), a privately-held U.S. Gulf of Mexico exploration and production company. The QuarterNorth Acquisition is expected to close during the first quarter of 2024. Consideration for the QuarterNorth Acquisition primarily consists of (i) approximately $964.9 million in cash, (ii) the amount of net unrestricted cash of QuarterNorth as of December 31, 2023 and (iii) 24.8 million shares of the Company's common stock.

**Divestiture**

***Mexico Divestiture —*** On September 27, 2023, the Company closed the sale of a 49.9% equity interest in its subsidiary, Talos Energy Mexico 7, S. de R.L. de C.V. ("Talos Mexico") to Zamajal, S.A. de C.V., a wholly owned subsidiary of Grupo Carso, for $74.9 million in cash consideration with an additional $49.9 million contingent on first oil production from the Zama Field (the "Mexico Divestiture"). The contingent consideration will be recognized when regular commercial production from the Zama Field becomes probable. Talos Mexico, through its wholly owned subsidiary, holds a 17.4% unitized interest in the Zama Field.

As a result of the Mexico Divestiture, Talos Mexico was deconsolidated on September 27, 2023 and is now accounted for as an equity method investment. Total assets derecognized included $112.3 million of unproved properties associated with exploration and appraisal activities in Block 7 located in the shallow waters off the coast of Mexico's Tabasco state. The fair value of the Company's retained equity method investment in Talos Mexico was $107.6 million. The determination of fair value was based on the implied fair value of Talos Mexico. The implied fair value of Talos Mexico was based on the transaction price of the Mexico Divestiture, which was an orderly transaction between market participants. A gain of $66.2 million was recognized on the Mexico Divestiture during the year ended December 31, 2023 which is included in "Other operating (income) expense" on the Consolidated Statements of Operations.

## Note 4 — Property, Plant and Equipment

**Proved Properties**

The Company's interests in oil and natural gas proved properties are located in the United States, primarily in the Gulf of Mexico deep and shallow waters. During 2023, 2022 and 2021, the Company's ceiling test computations did not result in a write-down of its U.S. oil and natural gas properties. At December 31, 2023, its ceiling test computation was based on SEC pricing of $78.56 per Bbl of oil, $2.75 per Mcf of natural gas and $18.77 per Bbl of NGLs.

**Unproved Properties**

Unproved capitalized costs of oil and natural gas properties excluded from amortization relate to unevaluated properties associated with acquisitions, leases awarded in the U.S. Gulf of Mexico federal lease sales, certain geological and geophysical costs, expenditures associated with certain exploratory wells in progress and capitalized interest.

During the year ended December 31, 2023, the Company derecognized $112.3 million of unproved properties associated with the exploration and appraisal activities in Block 7 located in the shallow waters off the coast of Mexico's Tabasco state. See Note 3 — *Acquisitions and Divestitures* for additional discussion.

During the year ended December 31, 2021, the Company's evaluation of unproved property located offshore Mexico resulted in a non-cash impairment of $18.1 million presented as "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations. The non-cash impairment was primarily attributable to the Company's operations in offshore Mexico in Block 31 associated with the Company's non-consent of the proposed appraisal plan during the fourth quarter of 2021.

The following table sets forth a summary of the Company's oil and natural gas property costs not being amortized at December 31, 2023, by the year in which such costs were incurred (in thousands):

| | | Year Ended December 31, | | | |
|---|---|---|---|---|---|
| | Total | 2023 | 2022 | 2021 | 2020 and Prior |
| Acquisition United States | $ 249,799 | $ 229,216 | $ — | $ — | $ 20,583 |
| Exploration United States | 18,516 | 10,108 | 1,299 | 2,295 | 4,814 |
| Total unproved properties, not subject to amortization | $ 268,315 | $ 239,324 | $ 1,299 | $ 2,295 | $ 25,397 |

The excluded costs will be included in the amortization base as properties are evaluated and proved reserves are established or impairment is determined. The unproved costs will be excluded from the amortization base until the Company has made a determination as to the existence of proved reserves. The Company currently estimates these costs will be transferred to the amortization base over eight years.

**Note 5 — Leases**

The Company has operating leases principally for office space, drilling rigs, compressors and other equipment necessary to support the Company's operations. Additionally, the Company has a finance lease related to the use of the Helix Producer I (the "HP-I"), a dynamically positioned floating production facility that interconnects with the Phoenix Field through a production buoy. The HP-I is utilized in the Company's oil and natural gas development activities and the ROU asset was capitalized and included in proved property and depleted as part of the full cost pool. Once items are included in the full cost pool, they are indistinguishable from other proved properties. The capitalized costs within the full cost pool are amortized over the life of the total proved reserves using the unit-of-production method, computed quarterly. Costs associated with the Company's leases are either expensed or capitalized depending on how the underlying asset is utilized.

In November 2022, the Company exercised its option to extend the lease of the HP-I through June 1, 2024. The extension resulted in a remeasurement of the lease liability to $166.3 million and corresponding adjustment to proved property.

The lease costs described below are presented on a gross basis and do not represent the Company's net proportionate share of such amounts. A portion of these costs have been or may be billed to other working interest owners. The Company's share of these costs is included in property and equipment, lease operating expense or general and administrative expense, as applicable. The components of lease costs were as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Finance lease cost - interest on lease liabilities | $ 14,476 | $ 7,558 | $ 11,453 |
| Operating lease cost, excluding short-term leases(1) | 4,883 | 2,281 | 2,706 |
| Short-term lease cost(2) | 117,132 | 55,072 | 38,472 |
| Variable lease cost(3) | 2,888 | 1,450 | 1,356 |
| Variable and fixed sublease income | (482) | — | — |
| Total lease cost | $ 138,897 | $ 66,361 | $ 53,987 |

(1) Operating lease cost reflect a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a straight-line basis.

(2) Short-term lease costs are reported at gross amounts and primarily represent costs incurred for drilling rigs, most of which are short-term contracts not recognized as a ROU asset and lease liability on the Consolidated Balance Sheets.

(3) Variable lease costs primarily represent differences between minimum payment obligations and actual operating charges incurred by the Company related to its long-term leases.

The present value of the fixed lease payments recorded as the Company's ROU asset and liability, adjusted for initial direct costs and incentives were as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Operating leases: | | |
| Operating lease assets | $ 11,418 | $ 5,903 |
| | | |
| Current portion of operating lease liabilities | $ 2,666 | $ 1,943 |
| Operating lease liabilities | 18,211 | 14,855 |
| Total operating lease liabilities | $ 20,877 | $ 16,798 |
| | | |
| Finance leases: | | |
| Proved properties | $ 166,261 | $ 166,261 |
| | | |
| Other current liabilities | $ 17,834 | $ 16,306 |
| Other long-term liabilities | 131,230 | 149,064 |
| Total finance lease liabilities | $ 149,064 | $ 165,370 |

The table below presents the lease maturity by year as of December 31, 2023 (in thousands). Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the Consolidated Balance Sheets.

| | Operating Leases | Finance Leases |
|---|---|---|
| 2024 | $ 4,748 | $ 30,782 |
| 2025 | 4,716 | 30,782 |
| 2026 | 4,803 | 30,782 |
| 2027 | 4,708 | 30,782 |
| 2028 | 4,610 | 30,782 |
| Thereafter | 4,584 | 43,608 |
| Total lease payments | $ 28,169 | $ 197,518 |
| Imputed interest | (7,292) | (48,454) |
| Total lease liabilities | $ 20,877 | $ 149,064 |

The table below presents the weighted average remaining lease term and discount rate related to leases:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Weighted average remaining lease term: | | | |
| Operating leases | 5.9 years | 6.4 years | 7.4 years |
| Finance leases | 6.4 years | 7.4 years | 1.4 years |
| Weighted average discount rate: | | | |
| Operating leases | 10.8% | 11.8% | 11.9% |
| Finance leases | 9.2% | 9.2% | 21.9% |

The table below presents the supplemental cash flow information related to leases (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Operating cash outflow from finance leases | $ 14,476 | $ 7,181 | $ 11,453 |
| Operating cash outflow from operating leases | $ 6,318 | $ 3,722 | $ 3,864 |
| | | | |
| ROU assets obtained in exchange for new finance lease liabilities | $ — | $ 166,261 | $ — |
| ROU assets obtained in exchange for new operating lease liabilities[1] | $ 12,971 | $ 474 | $ 1,020 |
| Remeasurement of lease liability arising from modification of ROU asset[2] | $ (5,124) | $ — | $ — |

(1) See EnVen Acquisition in Note 3 — *Acquisitions and Divestitures*.

(2) Lease termination accounted for as a lease modification based on the modified lease term. The termination did not take effect contemporaneously with the effective date of the modification.

## Note 6 — Financial Instruments

As of December 31, 2023 and 2022, the carrying amounts of cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximate their fair values because they are highly liquid or due to the short-term nature of these instruments.

### Debt Instruments

The following table presents the carrying amounts, net of discount and deferred financing costs, and estimated fair values of the Company's debt instruments (in thousands):

| | December 31, 2023 | | December 31, 2022 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| 12.00% Second-Priority Senior Secured Notes – due January 2026 | $ 601,353 | $ 655,130 | $ 590,132 | $ 674,542 |
| 11.75% Senior Secured Second Lien Notes – due April 2026 | $ 234,221 | $ 233,410 | $ — | $ — |
| Bank Credit Facility – matures March 2027 | $ 190,100 | $ 200,000 | $ (4,792) | $ — |

The carrying value of the senior notes are adjusted for discount, premium and deferred financing costs. Fair value is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices and, where such prices are not available, other observable (Level 2) inputs are used such as quoted prices for similar liabilities in the active markets.

The carrying amount of the Company's bank credit facility, as amended and restated (the "Bank Credit Facility"), is presented net of deferred financing costs. The fair value of the Bank Credit Facility is estimated based on the outstanding borrowings under the Bank Credit Facility since it is secured by the Company's reserves and the interest rates are variable and reflective of market rates (representing a Level 2 fair value measurement).

### Oil and Natural Gas Derivatives

The Company attempts to mitigate a portion of its commodity price risk and stabilize cash flows associated with sales of oil and natural gas production. The Company is currently utilizing oil and natural gas swaps and costless collars. Swaps are contracts where the Company either receives or pays depending on whether the oil or natural gas floating market price is above or below the contracted fixed price. Costless collars consist of a purchased put option and a sold call option with no net premiums paid to or received from counterparties. Typical collar contracts require payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

In connection with the EnVen Acquisition, the Company assumed oil and natural gas collar contracts that combine a two-way collar with a short put that holds an exercise price below the floor price ("three-way collar"). In these contracts, when the NYMEX average closing price is below the floor price, the Company receives the difference between the NYMEX average closing price and the floor price, capped at the difference between the floor price and the short put price.

The following table presents the impact that derivatives, not designated as hedging instruments, had on its Consolidated Statements of Operations (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Net cash received (paid) on settled derivative instruments | $ (9,457) | $ (425,559) | $ (290,164) |
| Unrealized gain (loss)(1) | 90,385 | 153,368 | (128,913) |
| Price risk management activities income (expense) | $ 80,928 | $ (272,191) | $ (419,077) |

(1) Includes $1.4 million gain from the unrealized derivative instruments acquired from the EnVen Acquisition for the year ended December 31, 2023.

The following tables reflect the contracted average daily volumes and weighted average prices under the terms of the Company's derivative contracts as of December 31, 2023:

**Swap Contracts**

| Production Period | Settlement Index | Volumes | Swap Price |
|---|---|---|---|
| Crude oil: | | *(Bbls)* | *(per Bbl)* |
| January 2024 – December 2024 | NYMEX WTI CMA | 16,859 | $ 74.30 |
| January 2025 – December 2025 | NYMEX WTI CMA | 7,734 | $ 73.80 |
| Natural gas: | | *(MMBtu)* | *(per MMBtu)* |
| January 2024 – December 2024 | NYMEX Henry Hub | 18,716 | $ 3.41 |
| January 2025 – December 2025 | NYMEX Henry Hub | 13,712 | $ 3.92 |

| Two-Way Collar Contracts | | | | |
|---|---|---|---|---|
| **Production Period** | **Settlement Index** | **Volumes** | **Floor Price** | **Ceiling Price** |
| Crude oil: | | *(Bbls)* | *(per Bbl)* | *(per Bbl)* |
| January 2024 – December 2024 | NYMEX WTI CMA | 1,497 | $ 70.00 | $ 79.32 |
| Natural gas: | | *(MMBtu)* | *(per MMBtu)* | *(per MMBtu)* |
| January 2024 – December 2024 | NYMEX Henry Hub | 10,000 | $ 4.00 | $ 6.90 |

| Three-Way Collar Contracts | | | | | |
|---|---|---|---|---|---|
| **Production Period** | **Settlement Index** | **Volumes** | **Short Put Price** | **Floor Price** | **Ceiling Price** |
| Crude oil: | | *(Bbls)* | *(per Bbl)* | *(per Bbl)* | *(per Bbl)* |
| January 2024 – March 2024 | NYMEX WTI CMA | 3,200 | $ 57.27 | $ 70.00 | $ 98.01 |

The following tables provide additional information related to financial instruments measured at fair value on a recurring basis (in thousands):

| | December 31, 2023 | | | |
|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Assets: | | | | |
| Oil and natural gas derivatives | $ — | $ 53,703 | $ — | $ 53,703 |
| Liabilities: | | | | |
| Oil and natural gas derivatives | — | (8,100) | — | (8,100) |
| Total net asset (liability) | $ — | $ 45,603 | $ — | $ 45,603 |

| | December 31, 2022 | | | |
|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Assets: | | | | |
| Oil and natural gas derivatives | $ — | $ 32,883 | $ — | $ 32,883 |
| Liabilities: | | | | |
| Oil and natural gas derivatives | — | (76,242) | — | (76,242) |
| Total net asset (liability) | $ — | $ (43,359) | $ — | $ (43,359) |

**Financial Statement Presentation**

Derivatives are classified as either current or non-current assets or liabilities based on their anticipated settlement dates. Although the Company has master netting arrangements with its counterparties, the Company presents its derivative financial instruments on a gross basis in its Consolidated Balance Sheets. The following table presents the fair value of derivative financial instruments as well as the potential effect of netting arrangements on the Company's recognized derivative asset and liability amounts (in thousands):

| | December 31, 2023 | | December 31, 2022 | |
|---|---|---|---|---|
| | **Assets** | **Liabilities** | **Assets** | **Liabilities** |
| Oil and natural gas derivatives: | | | | |
| Current | $ 36,152 | $ 7,305 | $ 25,029 | $ 68,370 |
| Non-current | 17,551 | 795 | 7,854 | 7,872 |
| Total gross amounts presented on balance sheet | 53,703 | 8,100 | 32,883 | 76,242 |
| Less: Gross amounts not offset on the balance sheet | 8,100 | 8,100 | 32,883 | 32,883 |
| Net amounts | $ 45,603 | $ — | $ — | $ 43,359 |

**Credit Risk**

The Company is subject to the risk of loss on its financial instruments as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The Company has entered into International Swaps and Derivative Association agreements with counterparties to mitigate this risk. The Company also maintains credit policies with regard to its counterparties to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of counterparties' credit exposures; (iii) the use of contract language that affords the Company netting or set off opportunities to mitigate exposure risk; and (iv) potentially requiring counterparties to post cash collateral, parent guarantees, or letters of credit to minimize credit risk. The Company's assets and liabilities from commodity price risk management activities at December 31, 2023 represent derivative instruments from nine counterparties; all of which are registered swap dealers that have an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating, and eight of which are parties under the Company's Bank Credit Facility. The Company enters into derivatives directly with these counterparties and, subject to the terms of the Company's Bank Credit Facility, is not required to post collateral or other securities for credit risk in relation to the derivative activities. Had the Company's counterparties failed to perform under existing commodity derivative contracts the maximum loss at December 31, 2023 would have been $45.6 million.

## Note 7 — Equity Method Investments

The following table presents the Company's investments in unconsolidated affiliates by segment for the periods indicated below. The Company accounts for these investments using the equity method of accounting.

| | Ownership Interest at December 31, 2023 | Year Ended December 31, 2023 | Year Ended December 31, 2022 |
|---|---|---|---|
| Upstream: | | | |
| Talos Energy Mexico 7, S. de R.L. de C.V | 50.1% | $ 107,259 | $ — |
| SP 49 Pipeline LLC | 33.3% | 861 | 374 |
| CCS: | | | |
| Bayou Bend CCS LLC | 25.0% | 28,183 | 1,371 |
| Harvest Bend CCS LLC | 65.0% | 9,746 | — |
| Coastal Bend CCS LLC | 50.0% | — | — |
| Total Equity Method Investments | | $ 146,049 | $ 1,745 |

### Talos Energy Mexico 7, S. de R.L. de C.V.

See Note 3 – *Acquisitions and Divestitures* for additional information on the deconsolidation of Talos Mexico. There is $66.0 million positive basis difference related to this investment, which will be amortized on a units of production method once regular commercial production from the Zama Field commences.

### Bayou Bend CCS LLC

On March 8, 2022, the Company made a $2.3 million cash contribution for a 50% membership interest in Bayou Bend CCS LLC ("Bayou Bend"). Bayou Bend has a CCS site that is in the early stages of development located offshore Jefferson County, Texas, near the Beaumont and Port Arthur, Texas industrial corridor. In May 2022, the Company sold a 25% membership interest to Chevron U.S.A. Inc. ("Chevron") for upfront cash consideration of $15.0 million. The Company recognized a $13.9 million gain on the partial sale of its investment in Bayou Bend during the year ended December 31, 2022, which is included in "Equity method investment income (expense)" on the Consolidated Statement of Operations. Chevron also agreed to fund up to $10.0 million of contributions to Bayou Bend on the Company's behalf, which was fully funded by the first quarter of 2023. The Bayou Bend investment was increased with an offsetting gain as the capital carry was funded by Chevron. The Company recognized an $8.6 million and $1.4 million gain during the years ended December 31, 2023 and 2022, respectively, on the funding of the capital carry of its investment in Bayou Bend. This gain is included in "Equity method investment income (expense)" on the Consolidated Statements of Operations.

Effective March 1, 2023, Chevron became the operator of Bayou Bend. During March 2023, Bayou Bend expanded its storage footprint through the acquisition of onshore acreage in Chambers and Jefferson Counties, Texas located within the Houston Ship Channel, Beaumont and Port Arthur region.

### VIE Disclosures

***VIE and Primary Beneficiary Determination —*** Talos Mexico, Bayou Bend, Harvest Bend CCS LLC ("Harvest Bend"), and Coastal Bend CCS LLC ("Coastal Bend") were each determined to be a VIE. Neither Talos Mexico, Bayou Bend, Harvest Bend, nor Coastal Bend had sufficient equity at risk to finance their respective activities without additional subordinated financial support. The Company is not the primary beneficiary of these VIE's due to the governance structure of these entities. The most significant activities of these entities are jointly controlled by the owners. The level of the Company's economic interest in Harvest Bend is not indicative of the amount of power held.

***Financings —*** All of the Company's VIE's have historically been funded through equity contributions from owners.

***Maximum Exposure —*** The Company's maximum exposure to loss as result of its involvement with VIE's is the carrying amount of each investment.

***Nature of Risks —*** Talos Mexico holds a working interest in the unitized Zama Field. In March 2023, Petróleos Mexicanos submitted the Zama Unit Development Plan ("UDP") to Mexico's governmental agency for approval and the UDP received approved in June 2023. An Integrated Project Team ("IPT") was formed in March 2023 to pool the talents and competencies of all companies participating in the development of the Zama Field. The IPT reports to the Zama Unit Operating Committee, which includes representatives from each of the participating companies. Final Investment Decision ("FID") is expected following completion and final review of the front-end engineering and design ("FEED"), project financing and final approvals. Achieving FID is a crucial stage and marks the beginning of the engineering and construction stage, where project contractors proceed with procuring material and beginning the construction. Availability of equipment and unexpected construction hurdles could delay the start of oil and gas production. Even though an IPT exists, teamwork could remain a challenge. There is also a risk that the project will not be completed within the budget and timeline, which ultimately could have an adverse impact on the net present value of the project.

The successful development of our CCS projects is dependent on various economic, regulatory, operational and technical factors. The failure to satisfy, wholly or in a significant measure, any of such factors could have a material adverse impact on the Company's business, results of operations and financial condition. For example, successful development of CCS projects in the United States requires compliance with stringent and varied regulatory schemes including obtaining Class VI well permits that are applicable to subsurface injection of $CO_2$ for geologic sequestration. Locating a suitable source of anthropogenic $CO_2$ and reaching suitable agreements to capture that $CO_2$ is crucial. Infrastructure to transport $CO_2$ between the source and CCS project sites is also required. In project areas with existing $CO_2$ transportation pipelines, reaching an agreement on $CO_2$ transportation with operators of such pipelines will be necessary. Inability to reach a suitable agreement may render a project uneconomic or impracticable. Separately, if no $CO_2$ pipelines exist in proposed project areas, or if existing pipelines do not extend to one or more of the Company's project sites, conversion of existing pipelines or construction of new pipelines or lateral connections will be required, which may render one or more projects uneconomic. Given the capital-intensive nature of CCS projects, project finance plays a critical role in accelerating the development of the Company's projects. If the Company is unable to obtain acceptable financing for its CCS projects, then it could result in significant delays in the development and construction of such projects. Lastly, the development of CCS projects is incentivized by tax credits provided under Section 45Q of the Internal Revenue Code of 1986, as amended. The Company's inability to benefit from such tax credits could prevent the development of the Company's projects.

**Note 8 — Debt**

A summary of the detail comprising the Company's debt and the related book values for the respective periods presented is as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| 12.00% Second-Priority Senior Secured Notes – due January 2026 | $ 638,541 | $ 638,541 |
| 11.75% Senior Secured Second Lien Notes – due April 2026 | 227,500 | — |
| Bank Credit Facility – matures March 2027 | 200,000 | — |
| Total debt, before discount, premium and deferred financing cost | 1,066,041 | 638,541 |
| Unamortized discount, premium and deferred financing cost, net | (40,367) | (53,201) |
| Total debt | 1,025,674 | 585,340 |
| Less: Current portion of long-term debt | 33,060 | — |
| Long-term debt | $ 992,614 | $ 585,340 |

**12.00% Second-Priority Senior Secured Notes**

The 12.00% Second-Priority Senior Secured Notes due 2026 (the "12.00% Notes") were issued pursuant to an indenture dated January 4, 2021 and the first supplemental indenture dated January 14, 2021 between the Parent Company (the "Parent Guarantor"), Talos Production Inc. (the "Issuer"), and certain of the Issuer's subsidiaries (the "Subsidiary Guarantors" and, together with the Parent Guarantor, the "Guarantors") and Wilmington Trust, National Association, as trustee and collateral agent. The 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indentures. The 12.00% Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by the Parent Guarantor and on a second-priority senior secured basis by each of the Subsidiary Guarantors and will be unconditionally guaranteed on the same basis by certain of the Issuer's future subsidiaries. The 12.00% Notes are secured on a second-priority basis by liens on substantially the same collateral as the collateral securing the Issuer's existing first-priority obligations under its Bank Credit Facility. The 12.00% Notes mature January 15, 2026 and have interest payable semi-annually each January 15 and July 15.

The Company may redeem all or a portion of the 12.00% Notes in whole at any time or in part from time to time at the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest if redeemed during the period commencing on January 15 of the years set forth below:

| Period | Redemption Price |
|---|---|
| 2023 | 106.000% |
| 2024 | 103.000% |
| 2025 and thereafter | 100.000% |

The indenture governing the 12.00% Notes applies certain limitations on the Company's ability and the ability of its subsidiaries to, among other things, (i) incur, assume or guarantee additional indebtedness or issue certain convertible or redeemable equity securities; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests, repurchase equity securities or redeem junior lien, unsecured or subordinated indebtedness; (iv) make investments; (v) restrict distributions, loans or other asset transfers from Talos Production Inc.'s restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of Talos Production Inc.'s properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. The 12.00% Notes contain customary quarterly and annual reporting, financial and administrative covenants. The Company was in compliance with all debt covenants at December 31, 2023.

The Issuer initiated a notes consent solicitation on October 21, 2022, to obtain the requisite holders' consent to certain amendments to the indenture governing the Issuer's 12.00% Notes to permit the incurrence of indebtedness in respect of the 11.75% Senior Secured Second Lien Notes due 2026 of EnVen (the "Notes Consent Solicitation"). The Notes Consent Solicitation expired on October 27, 2022, with holders of 95.8% of the aggregate principal amount of the 12.00% Notes outstanding consenting. As a result, the Issuer entered into a second supplemental indenture to the base indenture on October 27, 2022, which became effective upon its execution. The Issuer offered holders of the 12.00% Notes consideration equal to 50 basis points times the principal amount of the 12.00% Notes held by such consenting holder ("Consent Fee"). On February 13, 2023, the Issuer paid the Consent Fee of approximately $3.1 million in the aggregate in connection with the EnVen Acquisition.

During the year ended December 31, 2022, the Company repurchased $11.5 million of the 12.00% Notes. The debt repurchases resulted in a loss on extinguishment of debt for the year ended December 31, 2022 of $1.6 million, which is presented as "Other income (expense)" on the Consolidated Statements of Operations.

***Subsequent Event* —** On January 23, 2024, the Company issued a conditional notice to redeem in full the 12.00% Notes at a redemption price of 103.00% of the principal amount thereof, plus accrued and unpaid interest to, but excluding, the redemption date, in accordance with the 12.00% Notes indenture. The 12.00% Notes were redeemed on February 7, 2024 for $662.4 million utilizing the net proceeds from the Debt Offering (as defined below).

**11.75% Senior Secured Second Lien Notes**

On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Company assumed EnVen's 11.75% Senior Secured Second Lien Notes due 2026 (the "11.75% Notes") with a principal amount of $257.5 million. The 11.75% Notes mature on April 15, 2026 and interest accrues and is to be paid semi-annually in cash in arrears on April 15th and October 15th of each year. The indenture governing the 11.75% Notes requires the redemption of $15.0 million of the principal amount outstanding at par value on April 15th and October 15th of each year.

The Company may redeem all or a portion of the 11.75% Notes in whole at any time or in part from time to time at the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest if redeemed during the period commencing on February 15 of the years set forth below:

| Period | Redemption Price |
|---|---|
| 2023 | 105.875% |
| 2024 | 102.938% |
| 2025 and thereafter | 100.000% |

The 11.75% Notes are governed by an indenture by and among Energy Ventures GoM LLC, EnVen Finance Corporation as co-issuers, the guarantors party thereto and Wilmington Trust, National Association as trustee and collateral agent, dated as of April 15, 2021 ("11.75% Notes Indenture"). Talos Production Inc. and certain of its subsidiaries entered into a supplemental indenture to the 11.75% Notes Indenture which, inter alia, provides for the assumption of the indebtedness in respect of the 11.75% Notes by Talos Production Inc., as well as guarantees of such indebtedness by certain subsidiaries of Talos Production Inc., as contemplated by the terms of the 11.75% Notes Indenture.

The 11.75% Notes Indenture contains certain covenants, which are customary with respect to non-investment grade debt securities, including limitations on the Company's ability to incur and guarantee additional indebtedness, repay, redeem, or repurchase certain debt and capital stock, issue certain preferred stock or similar equity securities, pay dividends or make other distributions on capital stock, enter into certain types of transactions with affiliates, make loans or investments, and make other restricted payments. Additionally, certain covenants restrict Talos Production Inc. subsidiaries' ability to pay dividends, create liens, and sell certain assets.

***Subsequent Event* —** On January 26, 2024, the Company issued a conditional notice to redeem in full the 11.75% Notes at a redemption price of 102.938% of the principal amount thereof, plus accrued and unpaid interest to, but excluding, the redemption date, in accordance with the 11.75% Notes Indenture. The Company irrevocably deposited funds with the trustee sufficient to satisfy and discharge the 11.75% Notes Indenture and the 11.75% Notes until redeemed on April 15, 2024 with the funds deposited with the trustee and elected to satisfy and discharge the 11.75% Notes Indenture in accordance with its terms and the 11.75% Notes trustee acknowledged such discharge and satisfaction. The Company deposited $247.5 million with the trustee on February 7, 2024 utilizing the net proceeds from the Debt Offering.

**11.00% Second-Priority Senior Secured Notes**

On January 13, 2021, the Company redeemed $347.3 million aggregate principal amount of the 11.00% Second-Priority Senior Secured Notes due 2022 (the "11.00% Notes") at 102.75% plus accrued and unpaid interest using the proceeds from the issuance of the 12.00% Notes. The debt redemption resulted in a loss on extinguishment of debt of $13.2 million for the year ended December 31, 2021, which is included in "Other income (expense)" on the Consolidated Statements of Operations.

**7.50% Senior Notes**

The 7.50% Senior Notes due 2022 matured on May 31, 2022 and were redeemed at an aggregate principal of $6.1 million plus accrued and unpaid interest.

**Bank Credit Facility**

The Company maintains a Bank Credit Facility with a syndicate of financial institutions. The Bank Credit Facility provides for the determination of the borrowing base based on the Company's proved producing reserves and a portion of the Company's proved undeveloped reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter of each year. On December 23, 2022, the Company entered into the Incremental Agreement and Ninth Amendment to Credit Agreement (the "Ninth Amendment"). The Ninth Amendment, among other things, (i) extended the maturity date of the Bank Credit Facility from November 12, 2024 to March 31, 2027, (ii) increased the borrowing base from $1.1 billion to $1.5 billion and (iii) increased commitments from $806.3 million to $965.0 million, in each case went into effect upon the closing of the EnVen Acquisition and the occurrence of certain events related thereto. On June 9, 2023, the borrowing base decreased from $1.5 billion to $1.1 billion and commitments were reaffirmed at $965.0 million as part of the biannual determination.

The Bank Credit Facility no longer bears interest at the applicable London InterBank Offered Rate plus the applicable margin. Interest under the Bank Credit Facility accrues at the Company's option either at an alternate base rate ("ABR") plus the applicable margin ("ABR Loans"), an adjusted term secured overnight financing rate ("SOFR") plus the applicable margin ("Term Benchmark Loans") or adjusted daily simple SOFR plus the applicable margin ("RFR Loans"). The ABR is based on the greater of (a) the prime rate, (b) a federal funds rate plus 0.5% or (c) the adjusted term SOFR for a one-month interest period plus 1.00%. The adjusted term SOFR is equal to the term SOFR for each applicable tenor (e.g., one-month, three-months, six-months, and twelve-months) calculated and published by the CME Group Inc. plus 0.10%. The adjusted daily simple SOFR is equal to the overnight SOFR calculated and published by the Federal Reserve Bank of New York plus 0.10%. In addition, the Company is obligated to pay a commitment fee on the unutilized portion of the commitments. The pricing grid below shows the applicable margin for Term Benchmark Loans, RFR Loans and ABR Loans as well as the commitment fee rate, in each case based upon the applicable borrowing base utilization percentage:

| Borrowing Base Utilization Percentage | Utilization | Term Benchmark Loans and RFR Loans | ABR Loans | Commitment Fee Rate |
|---|---|---|---|---|
| Level 1 | < 25% | 2.75% | 1.75% | 0.38% |
| Level 2 | ≥ 25% < 50% | 3.00% | 2.00% | 0.38% |
| Level 3 | ≥ 50% < 75% | 3.25% | 2.25% | 0.50% |
| Level 4 | ≥ 75% < 90% | 3.50% | 2.50% | 0.50% |
| Level 5 | ≥ 90% | 3.75% | 2.75% | 0.50% |

The Bank Credit Facility has certain debt covenants, the most restrictive of which is that the Company must maintain a Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) of no greater than 3.00 to 1.00 calculated each quarter utilizing the most recent twelve months to determine EBITDAX. The Company must also maintain a current ratio no less than 1.00 to 1.00 each quarter. Under the Bank Credit Facility, unutilized commitments are included in current assets in the current ratio calculation. The Bank Credit Facility is secured by, among other things, mortgages covering at least 85.0% of the oil and natural gas assets of the Company. The Bank Credit Facility is fully and unconditionally guaranteed by the Company and certain of its wholly-owned subsidiaries.

As of December 31, 2023, the Company's borrowing base was $1,075.0 million with total commitments of $965.0 million. Additionally, no more than $250.0 million of the Company's borrowing base can be used as letters of credit with current commitments at $150.0 million. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Bank Credit Facility. The Company was in compliance with all debt covenants at December 31, 2023. As of December 31, 2023, the Company had outstanding borrowings at a weighted average interest rate of 8.26%. See Note 14 — *Commitments and Contingencies* for the amount of letters of credit issued under the Bank Credit Facility as of December 31, 2023.

***Subsequent Event —*** On January 13, 2024, the Company entered into the Tenth Amendment to Credit Agreement (the "Tenth Amendment"). The Tenth Amendment, among other things, (i) permits the incurrence of additional indebtedness in order to fund the QuarterNorth Acquisition, with such indebtedness excluded from any reduction of the borrowing base that would otherwise result from such incurrence, and (ii) reaffirms the borrowing base at $1.1 billion effective upon closing of the QuarterNorth Acquisition.

**Limitation on Restricted Payments Including Dividends**

The Company has not historically declared or paid any cash dividends on its capital stock. However, to the extent the Company determines in the future that it may be appropriate to pay a special dividend or initiate a quarterly dividend program, the Company's ability to pay any such dividends to its stockholders may be limited to the extent its consolidated subsidiaries are limited in their ability to make distributions to the Parent Company, including the significant restrictions that the agreements governing the Company's debt impose on the ability of its consolidated subsidiaries to make distributions and other payments to the Parent Company. With respect to entities accounted for under the equity method, the Company's primary equity method investee as of December 31, 2023 did not have any undistributed earnings.

The Bank Credit Facility contains restrictions on the ability of Talos Production Inc. to transfer funds to the Parent Company in the form of cash dividends, loans or advances. The Bank Credit Facility restricts distributions and other payments to the Parent Company, subject to certain baskets and other exceptions described therein including the payment of operating expense incurred in the ordinary course of business and for income taxes attributable to its ownership in Talos Production Inc. Under the Bank Credit Facility, general distributions and other restricted payments may be made to the Company so long as after giving pro forma effect to the making of any such restricted payment (i) no default or event of default has occurred and is continuing; (ii) available commitments exceed 25% of the then effective loan limit; (iii) the pro forma current ratio of 1.0 to 1.0 is satisfied; and (iv) either (A) the Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) is not greater than 1.75 to 1.00 and the aggregate amount of such restricted payments does not exceed the Available Free Cash Flow Amount (as defined in the Bank Credit Facility) at the time made or (B) the Consolidated Total Debt to EBITDAX Ratio is not greater than 1.00 to 1.00.

In addition, the indenture governing the 12.00% Notes restricts the Company's consolidated subsidiaries from, directly or indirectly, among other things, declaring or paying any dividend on account of their equity securities, subject to certain limited exceptions described in the indenture. Such exceptions include, among other things, if (i) no default has occurred or would occur as a result thereof, (ii) immediately after giving effect to such transaction on a pro forma basis, the issuer could incur $1.00 of additional indebtedness in compliance with a fixed charge coverage ratio of 2.25 to 1.00, (iii) the ratio of the issuer's total debt to EBITDA ratio is not greater than 3.00 to 1.00, and (iii) if payments pursuant to such transaction, together with the aggregate amount of certain other restricted payments, is less than the cumulative credit permitted under the indenture.

The indenture governing the 11.75% Notes contains a similar restriction on the Company and its consolidated subsidiaries' ability to declare or pay dividends, subject to exceptions which include, among other things, (i) subject to no default or event of default having occurred or continuing, dividends in an aggregate amount not to exceed the greater of $25 million and 2.5% of Adjusted Consolidated Net Tangible Assets, (ii) dividends or distributions to any parent company to make payments, in lieu of issuing fractional shares in connection with share dividends, share splits, reverse share splits, mergers, consolidations, amalgamations or other business combinations and in connection with the exercise of warrants, options or other securities convertible into or exchangeable for equity interests of the Company.

At December 31, 2023, restricted net assets of the Company's consolidated subsidiaries exceeded 25%.

**Subsequent Event — Debt Offering**

On February 7, 2024, the Company closed an upsized offering (the "Debt Offering") for the sale of $1,250.0 million in aggregate principal amount of second-priority senior secured notes, consisting of $625.0 million aggregate principal amount of second-priority senior secured notes due 2029 and $625.0 million aggregate principal amount of second-priority senior secured notes due 2031 (collectively, the "New Senior Notes"), in a private offering to eligible purchasers that is exempt from registration under the Securities Act. The net proceeds from the Debt Offering (i) are expected to fund a portion of the cash consideration for the pending QuarterNorth Acquisition, (ii) funded the redemption of all of the outstanding 12.00% Notes and all of the outstanding 11.75% Notes discussed above (the "Redemptions"), and (iii) paid premiums, fees and expenses related to the Redemptions and the issuance of the New Senior Notes. The Company intends to use any remaining net proceeds for general corporate purposes, which may include the repayment of a portion of the outstanding borrowings under the Bank Credit Facility.

An aggregate of $340.0 million principal amount of the New Senior Notes will be subject to a "special mandatory redemption" in the event that the transactions contemplated by the QuarterNorth Merger Agreement are not consummated on or before May 31, 2024 (or up to September 30, 2024 solely in the event the parties require additional time to satisfy certain requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, pursuant to the terms of the QuarterNorth Merger Agreement), or if we notify the trustee of the New Senior Notes that we will not pursue the consummation of the QuarterNorth Acquisition.

**Note 9 — Asset Retirement Obligations**

The asset retirement obligations included in the Consolidated Balance Sheets in current and non-current liabilities, and the changes in that liability were as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Balance, beginning of period | $ 541,661 | $ 434,006 |
| Obligations assumed[1] | 258,858 | — |
| Obligations incurred | 14,199 | 1,140 |
| Obligations settled | (86,615) | (69,596) |
| Obligations divested | (19,448) | (1,572) |
| Accretion expense | 86,152 | 55,995 |
| Changes in estimate[2] | 102,419 | 121,688 |
| Balance, end of period | $ 897,226 | $ 541,661 |
| Less: Current portion | 77,581 | 39,888 |
| Long-term portion | $ 819,645 | $ 501,773 |

(1) Assumed in connection with the EnVen Acquisition. See further discussion in Note 3 — *Acquisitions and Divestitures*.

(2) Changes in estimate were primarily due to an increase in estimated service costs. Additionally, increases for the year ended December 31, 2023 due to the acceleration of estimated settlement date.

At December 31, 2023, the Company has (1) restricted cash of $102.4 million inclusive of interest earned to date, held in escrow and (2) the P&A Notes Receivable with an aggregate face value of $66.2 million to settle future asset retirement obligations. These assets are discussed in Note 2 — *Summary of Significant Accounting Policies*.

**Note 10 — Employee Benefits Plans and Share-Based Compensation**

**EnVen Acquisition Severance**

The following table summarizes severance accrual activity in connection with the EnVen Acquisition included in "Other current liabilities" and "Other long-term liabilities" on the Consolidated Balance Sheets as of December 31, 2023 (in thousands):

| | |
|---|---|
| Severance accrual at December 31, 2022 | $ — |
| Accrual additions | 25,348 |
| Benefit payments | (19,054) |
| Severance accrual at December 31, 2023 | 6,294 |
| Less: Current portion at December 31, 2023 | 6,190 |
| Long-term portion at December 31, 2023 | $ 104 |

The above table includes involuntary termination benefits that are being provided pursuant to a one-time benefit arrangement that is being spread over the future service period through the termination date. Involuntary termination benefits are also being provided pursuant to contractual termination benefits required by the terms of existing employee agreements. Pursuant to the EnVen Merger Agreement, a rabbi trust was established and funded with $14.5 million at closing to pay a portion of future severance benefits associated with the contractual termination benefits. As of December 31, 2023, the rabbi trust held $3.7 million in assets of which $3.3 million and $0.4 million are included in "Other current assets" and "Other assets," respectively, on the Consolidated Balance Sheets and both of which are included in the severance accrual at December 31, 2023 listed above. The assets of the rabbi trust are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Severance costs are reflected in "General and administrative expense" on the Consolidated Statement of Operations.

**Long Term Incentive Plans**

On May 11, 2021, the Company's stockholders approved the Talos Energy Inc. 2021 Long Term Incentive Plan (the "2021 LTIP"), which had previously been approved by the board of directors of the Company. No further awards will be granted under the Talos Energy Inc. Long Term Incentive Plan (the "2018 LTIP") (together with the 2021 LTIP, the "LTIP Plans").

The 2021 LTIP provides for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws ("ISOs"), (ii) stock options that do not qualify as ISOs (together with ISOs, "Options"), (iii) stock appreciation rights, (iv) restricted stock awards, (v) RSUs, (vi) awards of vested stock, (vii) dividend equivalents, (viii) other share-based or cash awards and (ix) substitute awards. Employees, non-employee directors and consultants of the Company and its affiliates are eligible to receive awards under the 2021 LTIP. The 2021 LTIP authorizes the Company to grant awards of up to 8,639,415 shares of the Company's common stock, subject to the share counting and share recycling provisions of the 2021 LTIP.

***Restricted Stock Units – Employees —*** RSUs granted to employees under the LTIP Plans primarily vest ratably over an approximate three year period subject to such employee's continued service through each vesting date. Upon vesting, each RSU represents a contingent right to receive one share of common stock. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2023 was approximately $19.0 million, which is expected to be recognized over a weighted average period of 1.7 years.

***Restricted Stock Units – Non-employee Directors*** — RSUs granted to non-employee directors under the LTIP Plans vested approximately one year following the date of grant, subject to such non-employee director's continued service through the vesting date. Upon vesting, these RSUs represent a contingent right to receive one share of common stock for each RSU for 60%, and cash for the remaining 40%. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2023 was approximately $0.1 million, which is expected to be recognized over a weighted average period of 0.2 years. Of the unrecognized share-based compensation expense, $0.1 million relates to liability awards and will be subsequently remeasured at each reporting period.

The following table summarizes RSU activity:

| | Restricted Stock Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested RSUs at December 31, 2020 | 1,652,988 | $ 13.73 |
| Granted | 1,102,038 | $ 13.11 |
| Vested | (669,832) | $ 15.01 |
| Forfeited | (101,995) | $ 12.46 |
| Unvested RSUs at December 31, 2021 | 1,983,199 | $ 13.02 |
| Granted | 2,297,465 | $ 13.23 |
| Vested | (967,269) | $ 14.14 |
| Forfeited | (97,891) | $ 14.34 |
| Unvested RSUs at December 31, 2022[(1)] | 3,215,504 | $ 12.79 |
| Granted | 1,154,541 | $ 16.24 |
| Vested | (1,730,959) | $ 11.97 |
| Forfeited | (332,725) | $ 14.52 |
| Unvested RSUs at December 31, 2023[(1)] | 2,306,361 | $ 14.89 |

(1) As of December 31, 2023 and 2022, 26,975 and 25,257, respectively, of the unvested RSUs were accounted for as liability awards in "Accrued liabilities" on the Consolidated Balance Sheet.

The Company considers its intent and ability to settle awards in cash or shares in determining whether to classify the awards as equity or as a liability. Certain awards granted during the year ended December 31, 2021 were originally classified as liability awards; however, these awards became equity-classified awards upon stockholder approval of the 2021 LTIP. The aggregate amount of compensation cost related to these awards is determined by the fair value of the award on the modification date.

***Performance Share Units – Employees*** — PSUs granted to employees under the LTIP Plans represent the contingent right to receive one share of common stock. However, the number of shares of common stock issuable upon vesting ranges from zero to 200% of the target number of PSUs granted. The total unrecognized share-based compensation expense related to these PSUs at December 31, 2023 was approximately $8.7 million, which is expected to be recognized over a weighted average period of 1.7 years.

The following table summarizes PSU activity:

| | Performance Share Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested PSUs at December 31, 2020 | 834,172 | $ 25.46 |
| Granted | 586,995 | $ 18.96 |
| Vested | (391,308) | $ 39.43 |
| Forfeited | (14,400) | $ 18.48 |
| Unvested PSUs at December 31, 2021 | 1,015,459 | $ 16.41 |
| Granted(1) | 629,666 | $ 23.73 |
| Vested(2) | (14,474) | $ 13.05 |
| Forfeited | (16,486) | $ 17.48 |
| Cancelled | (975,564) | $ 16.42 |
| Unvested PSUs at December 31, 2022 | 638,601 | $ 23.66 |
| Granted(3) | 595,394 | $ 18.76 |
| Forfeited | (217,346) | $ 21.28 |
| Unvested PSUs at December 31, 2023 | 1,016,649 | $ 21.30 |

(1) There were 314,833 PSUs granted that are eligible to vest based on continued employment and the Company's annualized absolute total shareholder return ("TSR") over a three-year performance period. An additional 314,833 PSUs were granted and are eligible to vest based on continued employment and the Company's return on the wells included in the 2022 drill program over a three-year performance period.

(2) The performance period for the relative TSR awards ended on December 31, 2022. The payout on these awards was 0% based on actual performance over the performance period as certified by the Compensation Committee of the Company's Board of Directors in early 2023. Since these awards were legally forfeited they will again be available for new awards under the recycling provisions of the 2021 LTIP.

(3) There were 297,697 PSUs granted that are eligible to vest based on continued employment and the Company's annualized absolute TSR over a three-year performance period. An additional 297,697 PSUs were granted and are eligible to vest based on continued employment and the Company's return on the wells included in the 2023 drill program over a three-year performance period.

Certain awards granted during the year ended December 31, 2021 were originally classified as liability awards; however, these awards became equity-classified awards upon stockholder approval of the 2021 LTIP. The following table summarizes the assumptions used in the Monte Carlo simulations to calculate the fair value of the relative or absolute TSR PSUs granted and modified at the date indicated:

| | 2023 | | | 2022 | | 2021 | |
|---|---|---|---|---|---|---|---|
| | Grant | Grant | Grant | Grant | Grant | Modification | Grant |
| | December 1 | July 1 | March 5 | September 20 | March 5 | May 11 | March 8 |
| Expected term (in years) | 2.1 | 2.5 | 2.8 | 2.3 | 2.8 | 2.6 | 2.8 |
| Expected volatility | 61.9 % | 66.2 % | 73.1 % | 74.3 % | 82.2 % | 80.9 % | 78.3 % |
| Risk-free interest rate | 4.4 % | 4.6 % | 4.5 % | 3.9 % | 1.6 % | 0.3 % | 0.3 % |
| Dividend yield | — % | — % | — % | — % | — % | — % | — % |
| Fair value (in thousands) | $ 12 | $ 173 | $ 6,165 | $ 621 | $ 8,668 | $ 9,715 | $ 11,129 |

***Modification*** — During March 2022, the outstanding PSUs held by certain executive officers that were awarded in 2020 and 2021 were cancelled and, in connection with this cancellation, 1,147,352 of RSUs were granted (the "Retention RSUs"). The Retention RSUs will vest ratably each year over two years, generally contingent upon continued employment through each such date. The cancellation of the PSUs along with the concurrent grant of the Retention RSUs are accounted for as a modification. The incremental cost of $9.7 million will be recognized prospectively over the modified requisite service period. Additionally, the remaining unrecognized grant or modification date fair value of the original PSUs will be recognized over the original remaining requisite service period.

**Share-based Compensation Costs**

Share-based compensation costs associated with RSUs, PSUs and other awards are reflected as "General and administrative expense" on the Consolidated Statements of Operations, net amounts capitalized to "Proved Properties" on the Consolidated Balance Sheets. Because of the non-cash nature of share-based compensation, the expensed portion of share-based compensation is added back to net income in arriving at "Net cash provided by operating activities" on the Consolidated Statements of Cash Flows.

The following table presents the amount of costs expensed and capitalized (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Share-based compensation costs | $ 25,236 | $ 28,280 | $ 20,560 |
| Less: Amounts capitalized to oil and gas properties | 12,283 | 12,327 | 9,568 |
| Total share-based compensation expense | $ 12,953 | $ 15,953 | $ 10,992 |

## Note 11 — Income Taxes

### Income Tax Expense (Benefit)

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Current income tax expense (benefit): | | | |
| United States | $ 76 | $ 1,375 | $ (5) |
| Mexico | 31 | 432 | (993) |
| Total current income tax expense (benefit) | $ 107 | $ 1,807 | $ (998) |
| | | | |
| Deferred income tax expense (benefit): | | | |
| United States | $ (60,704) | $ 659 | $ (1,067) |
| Mexico | — | 71 | 430 |
| Total deferred income tax expense (benefit) | $ (60,704) | $ 730 | $ (637) |
| | | | |
| Total income tax expense (benefit) | $ (60,597) | $ 2,537 | $ (1,635) |

A reconciliation of income tax expense (benefit) computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) is as follows (in thousands, except percentages):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Income tax expense (benefit) at the federal statutory tax rate | $ 26,614 | $ 80,735 | $ (38,763) |
| State income taxes | 1,748 | 1,591 | (674) |
| Impact of foreign operations | 13,539 | 15,657 | (11,920) |
| Effect of change in state rate | — | — | 2,008 |
| Prior year taxes | 1,184 | (2,920) | 486 |
| Change in valuation allowance | (106,815) | (96,537) | 45,547 |
| Other permanent differences | 3,133 | 4,011 | 1,681 |
| Total income tax expense (benefit) | $ (60,597) | $ 2,537 | $ (1,635) |
| Effective tax rate | (47.81)% | 0.66 % | 0.89 % |

The Company's effective tax rate for the year ended December 31, 2023 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax benefit of $106.8 million related to the release of the valuation allowance for its deferred tax assets offset with permanent differences and state income tax expense.

The Company's effective tax rate for the years ended December 31, 2022 and 2021 differed from the federal statutory rate of 21.0% primarily due to recording a full valuation allowance against its federal, state and foreign deferred tax assets.

**Deferred Tax Assets and Liabilities**

Net deferred tax assets (liabilities) reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of deferred tax assets and liabilities were as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2023 | 2022 |
| Deferred tax assets: | | |
| Federal net operating loss | $ 147,252 | $ 159,257 |
| Foreign tax loss carryforward | 509 | 44,462 |
| State net operating loss | 24,840 | 24,787 |
| Tax credits | 107 | 107 |
| Interest expense carryforward | 46,414 | 23,262 |
| Asset retirement obligations | 190,248 | 115,848 |
| Derivatives | — | 9,273 |
| Other well equipment | 1,317 | 1,891 |
| Accrued bonus | 5,050 | 5,863 |
| Share-based compensation | 5,172 | 5,296 |
| Operating lease liabilities | 4,427 | 3,669 |
| Finance lease liabilities | 31,607 | 32,559 |
| Other | 3,383 | 7,142 |
| Total deferred tax assets | 460,326 | 433,416 |
| Valuation allowance | (23,697) | (129,105) |
| Total deferred tax assets, net | $ 436,629 | $ 304,311 |
| Deferred tax liabilities: | | |
| Oil and gas properties | $ 512,918 | $ 302,602 |
| Operating lease assets | 2,421 | 1,323 |
| Derivatives | 9,670 | — |
| Prepaid | 3,847 | 2,530 |
| Total deferred tax liabilities | 528,856 | 306,455 |
| Net deferred tax liability | $ (92,227) | $ (2,144) |

**Net Operating Loss**

The table below presents the details of the Company's net operating loss carryovers as of December 31, 2023 (in thousands):

| | Amount | Expiration Year |
|---|---|---|
| Federal net operating losses | $ 452,393 | 2035 - 2037 |
| Federal net operating losses | $ 248,807 | Unlimited |
| Foreign tax loss carryforward | $ 1,696 | 2025 - 2032 |
| State net operating losses | $ 125,958 | 2025 - 2037 |
| State net operating losses | $ 277,930 | Unlimited |

As of December 31, 2023, the Company had U.S. federal net operating loss carryforwards ("NOLs") of approximately $701.2 million, all of which are subject to limitation under Section 382 of the IRC. IRC Section 382 provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, against future U.S. taxable income in the event of a change in ownership. If not utilized, such carryforwards would begin to expire at the end of 2035.

**Valuation Allowance**

The Company recorded a valuation allowance of $23.7 million and $129.1 million as of December 31, 2023 and 2022, respectively. Deferred income tax assets and liabilities are recorded related to NOLs and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions and income in the future. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs relate.

In assessing the need for a valuation allowance, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized using available positive and negative evidence, including future reversals of temporary differences, tax-planning strategies and future taxable income, to estimate whether sufficient future taxable income will be generated to permit use of deferred tax assets. A significant piece of objective negative evidence evaluated is the cumulative loss incurred over recent years. Such objective negative evidence limits the Company's ability to consider other subjective positive evidence.

At December 31, 2022, the Company maintained a valuation allowance related to federal, state and foreign deferred tax assets, as there was insufficient positive evidence to overcome the substantial negative evidence of being in a cumulative loss position. At December 31, 2023, the Company is no longer in a cumulative loss position and reached the conclusion that it is appropriate to release the valuation allowance against its federal deferred tax assets due to the sustained positive operating performance and the availability of expected future taxable income. The Company's remaining valuation allowance primarily relates to various state operating loss carryforwards.

**Uncertain Tax Positions**

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. None of the unrecognized benefits would impact the effective tax rate if recognized. While amounts could change during the next 12 months, the Company does not anticipate having a material impact on its financial statements.

Balances in the uncertain tax positions are as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Total unrecognized tax benefits, beginning balance | $ 835 | $ 696 | $ 648 |
| Increases in unrecognized tax benefits as a result of: | | | |
| Tax positions taken during a prior period | 154 | 100 | 21 |
| Tax positions taken during the current period | — | 39 | 27 |
| Total unrecognized tax benefits, ending balance | $ 989 | $ 835 | $ 696 |

The Company recognizes interest and penalties related to uncertain tax positions as "Interest Expense" and "General and administrative expense" on the Consolidated Statements of Operations, respectively.

**Years Open to Examination**

The 2020 through 2023 tax years remain open to examination by the tax jurisdictions in which the Company is subject to tax. The statute of limitations with respect to the U.S. federal income tax returns of the Company for years ending on or before December 31, 2019 are closed, except to the extent of any NOL carryover balance.

**EnVen Acquisition**

On February 13, 2023, the Company completed the EnVen Acquisition, which is further discussed in Note 3 —*Acquisitions and Divestitures*. The Company recognized a net deferred tax liability of $150.3 million in its purchase price allocation as of the acquisition date to reflect differences between tax basis and the fair value of EnVen's assets acquired and liabilities assumed. The deferred tax balance is based on preliminary calculations and on information available to management at the time such estimates were made.

**Note 12 — Income (Loss) Per Share**

Basic earnings per common share is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted earnings per common share includes the impact of RSUs, PSUs and outstanding warrants. The warrants expired unexercised on February 28, 2021.

The following table presents the computation of the Company's basic and diluted income (loss) per share were as follows (in thousands, except for the per share amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Net income (loss) | $ 187,332 | $ 381,915 | $ (182,952) |
| | | | |
| Weighted average common shares outstanding — basic | 119,894 | 82,454 | 81,769 |
| Dilutive effect of securities | 858 | 1,229 | — |
| Weighted average common shares outstanding — diluted | 120,752 | 83,683 | 81,769 |
| | | | |
| Net income (loss) per common share: | | | |
| Basic | $ 1.56 | $ 4.63 | $ (2.24) |
| Diluted | $ 1.55 | $ 4.56 | $ (2.24) |
| Anti-dilutive potentially issuable securities excluded from diluted common shares | 1,353 | 865 | 1,709 |

## Note 13 — Related Party Transactions

### Apollo Funds and Riverstone Funds

On February 3, 2012, Talos Energy LLC completed a transaction with funds and other alternative investment vehicles managed by Apollo Management VII, L.P. and Apollo Commodities Management, L.P., with respect to Series I ("Apollo Funds"), and entities controlled by or affiliated with Riverstone Energy Partners V, L.P. ("Riverstone Funds") and members of management pursuant to which the Talos Energy LLC received a private equity capital commitment. On January 3, 2022, the Apollo Funds ceased being a beneficial owner of more than five percent of the Company's common stock. On July 5, 2023, the Riverstone Funds ceased being a beneficial owner of more than five percent of the Company's common stock.

### Whistler Acquisition Settlement

On August 31, 2018, the Company acquired Whistler Energy II, LLC from Whistler Energy II Holdco, LLC, an affiliate of the Apollo Funds. A settlement agreement related to a dispute regarding the decommissioning obligation of a Deepwater well was executed in September 2021. For the year ended December 31, 2021, the Company recognized a $4.4 million gain resulting from the settlement which is reflected in "Other income (expense)" on the Company's Consolidated Statements of Operations.

### Registration Rights Agreements

***2018 Registration Rights Agreement —*** On May 10, 2018, the Company entered into a registration rights agreement (the "2018 Registration Rights Agreement") with certain of the Apollo Funds and the Riverstone Funds, certain funds controlled by Franklin Advisers, Inc. ("Franklin") and certain clients of MacKay Shields LLC ("MacKay Shields"), relating to the registered resale of the Company's common stock owned by such parties on such date. Subsequently, the 2018 Registration Rights Agreement was amended to add additional affiliates of the Riverstone Funds as parties to the agreement and provide such parties with customary registration rights with respect to the Company's Series A Convertible Preferred Stock issued to these parties at the closing of an acquisition on February 28, 2020.

The 2018 Registration Rights Agreement provided that registration rights would terminate with respect to Franklin and MacKay Shields in the event that either Franklin or MacKay Shields ceased to beneficially own 5% or more of the then outstanding shares of the Company's common stock. Additionally, the 2018 Registration Rights Agreement provided that registration rights would otherwise terminate at such time as there were no registrable securities outstanding. The 2018 Registration Rights Agreement terminated on July 5, 2023 as there were no registrable securities outstanding.

The Company agreed to bear all of the expenses incurred in connection with any offer and sale, while the selling stockholders will be responsible for paying underwriting fees, discounts and selling commissions. The Company incurred fees of nil, nil, and $0.7 million for the fiscal years ended December 31, 2023, 2022 and 2021, respectively.

***2022 Registration Rights Agreement —*** In connection with the Company's entry into the EnVen Merger Agreement on September 21, 2022 to acquire EnVen, the Company entered into a registration rights agreement (the "2022 Registration Rights Agreement") with Adage Capital Partners, L.P. ("Adage") and affiliated entities of Bain Capital, LP ("Bain"). Pursuant to the 2022 Registration Rights Agreement, the Company grants to Adage and Bain certain demand, "piggy-back" and shelf registration rights with respect to the shares of the Company's common stock to be received by such entities in the EnVen Acquisition, subject to certain customary thresholds and conditions. Adage and Bain held approximately 2.3% and 12.2%, respectively, of the Company's outstanding shares of common stock as of December 31, 2023 based on SEC beneficial ownership reports filed by each of Adage and Bain.

Additionally, the Company agreed to pay certain expenses of the parties incurred in connection with the exercise of their rights under such agreement and to indemnify them for certain securities law matters in connection with any registration statement filed pursuant thereto. The Company did not incur any fees for the fiscal year ended December 31, 2023.

### Amended and Restated Stockholders' Agreement and Related Agreements

On May 10, 2018, the Company entered into a Stockholders' Agreement (the "Stockholders' Agreement") by and among the Company and the other parties thereto. On February 24, 2020, the Company and the other parties thereto amended the Stockholders' Agreement to, among other things, add additional affiliates of the Riverstone Funds (or one or more of its designated affiliates) as parties to the Stockholders' Agreement and provided ownership of the Series A Convertible Preferred Stock would, prior to the conversion thereof on March 20, 2020, count towards certain stock ownership requirements on an as converted basis to retain the Riverstone Funds rights to nominate directors to the board of directors.

On March 29, 2022, the Company and other parties thereto, entered into the Amended and Restated Stockholders' Agreement, in connection with the termination of the Apollo Funds' rights thereunder and the resignation of certain members of the Company's Board of Directors (the "Amended and Restated Stockholders' Agreement"). The Amended and Restated Stockholders' Agreement, among other things, (i) terminated the rights of the Apollo Funds under the Stockholders' Agreement and (ii) eliminated the requirement that the board of directors consist of ten members.

In connection with the closing of the EnVen Acquisition, the Company and the Riverstone Funds terminated the Amended and Restated Stockholders' Agreement and Mr. Robert M. Tichio resigned from the Company's Board of Directors pursuant to a shareholder support agreement dated as of September 21, 2022 requiring the Riverstone Funds to, among other things, approve the EnVen Merger Agreement and the proposed business combination. In connection with the termination of the Amended and Restated Stockholders' Agreement, the Company and the Riverstone Funds entered into a letter agreement, dated February 13, 2023, pursuant to which the parties thereto agreed to execute and deliver such additional documents and take all such further action as may be reasonably necessary to cause the Amended and Restated Stockholders' Agreement to be terminated without any further force and effect.

**Legal Fees**

The Company has engaged the law firm Vinson & Elkins L.L.P. ("V&E") to provide legal services. An immediate family member of William S. Moss III, the Company's Executive Vice President and General Counsel and one of its executive officers, is a partner at V&E. For the years ended December 31, 2023, 2022 and 2021, the Company incurred fees of approximately $3.3 million, $4.8 million, and $3.1 million, respectively, of which $0.8 million, $1.3 million, and $0.2 million were payable at each respective balance sheet date for legal services performed by V&E.

**Slim Family**

Carlos Slim Helú, Carlos Slim Domit, Marco Antonio Slim Domit, Patrick Slim Domit, María Soumaya Slim Domit, Vanessa Paola Slim Domit and Johanna Monique Slim Domit (collectively, the "Slim Family") are beneficiaries of a Mexican trust which in turn owns all of the outstanding voting securities of Control Empresarial de Capitales S.A. de C.V. ("Control Empresarial" together with the Slim Family, the "Slim Family Office"). Control Empresarial, *a sociedad anónima de capital variable* organized under the laws of the United Mexican States, is a holding company with portfolio investments in various companies. Control Empresarial and the Slim Family became related parties on November 7, 2023 when they accumulated greater than ten percent of the Company's outstanding shares of common stock. Control Empresarial held approximately 12.2% of the Company's outstanding shares of common stock as of December 31, 2023 based on SEC beneficial ownership reports filed by Control Empresarial. The Slim Family own a majority stake in Grupo Carso, which indirectly has an ownership interest in Talos Mexico. See Note 3 – *Acquisitions and Divestitures* for additional information. The Company had no related party receivable from affiliates of the Slim Family as of December 31, 2023.

***Subsequent Event —*** In connection with the January Equity Offering (defined below), Control Empresarial increased their holding to approximately 21.9% of the Company's outstanding shares of common stock as of the closing of the January Equity Offering based on SEC beneficial ownership reports filed by Control Empresarial. See Note 17 – *Subsequent Events* for additional information.

In connection with the Debt Offering in February 2024, the Company consummated a firm commitment debt offering consisting of $1,250.0 million in aggregate principal amount of second-priority senior secured notes in a private offering to eligible purchasers that was exempt from registration under the Securities Act. In connection with the Debt Offering, and after expressing a non-binding indication of interest after commencement of the offering, entities and/or persons related to the Slim Family Office purchased an aggregate principal amount of $312.5 million of such notes from the initial purchasers of such offering. In connection with such transaction, the Company expects to pay Inbursa, a banking institution controlled by the Slim Family Office an advisory fee of approximately $2.7 million. See Note 8 – *Debt* for additional information regarding the Debt Offering.

**Equity Method Investments**

The Company had a $5.5 million related party receivable from various equity method investments as of December 31, 2023. This is reflected as "Other, net" within "Accounts Receivable" on the Consolidated Balance Sheets. See Note 7 – *Equity Method Investments* for additional information on the Company's equity method investments.

## Note 14 — Commitments and Contingencies

### Legal Proceedings and Other Contingencies

From time to time, the Company is involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of business in jurisdictions in which the Company does business. Although the outcome of these matters cannot be predicted with certainty, the Company's management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on the Company's results from operations for a specific interim period or year.

On March 23, 2022, the Company entered into a settlement agreement to receive $27.5 million to resolve previously pending litigation, which was filed on October 23, 2017, against a third-party supplier related to quality issues. As part of the settlement agreement, the Company released all of its claims in the litigation. The settlement is reflected as "Other income (expense)" on the Consolidated Statements of Operations.

In June 2019, David M. Dunwoody, Jr., former President of EnVen, filed a lawsuit against EnVen in Texas District Court alleging that the circumstances of his resignation entitled him to the severance payments and benefits under his employment agreement dated as of November 6, 2015 as a resignation for "Good Reason." In September 2021, the trial court entered a judgment in favor or Mr. Dunwoody, inclusive of Mr. Dunwoody's legal fees and interest. EnVen filed a Notice of Appeal in December 2021. The litigation was assumed as part of the EnVen Acquisition. In April 2023, the appellate court affirmed the trial court's judgment. The Company filed a petition for review with the Texas Supreme Court on August 2, 2023, which was denied on January 26, 2024. As Of December 31, 2023, the Company has recorded $14.3 million as "Other current liabilities" on the Consolidated Balance Sheets related to the litigation.

**Performance Obligations**

Regulations with respect to the Company's operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, removal of facilities in the U.S. Gulf of Mexico and certain obligations under the production sharing contracts with Mexico.

As of December 31, 2023, the Company had secured performance bonds from third party sureties totaling $1.4 billion. The cost of securing these bonds is reflected as "Interest expense" on the Consolidated Statements of Operations. Additionally, as of December 31, 2023, the Company had secured letters of credit issued under its Bank Credit Facility totaling $10.8 million. Letters of credit that are outstanding reduce the available revolving credit commitments. See Note 8 — *Debt* for further information on the Bank Credit Facility.

The table below summarizes the Company's total minimum commitments associated with vessel commitments, purchase obligations and other miscellaneous commitments as of December 31, 2023 (in thousands):

| | 2024 | 2025 | 2026 | 2027 | Thereafter | Total |
|---|---|---|---|---|---|---|
| Vessel Commitments(1) | $ 13,216 | $ — | $ — | $ — | $ — | $ 13,216 |
| Committed purchase orders(2) | 3,083 | — | — | — | — | 3,083 |
| Other commitments(3) | 3,991 | 327 | — | — | — | 4,318 |
| Total | $ 20,290 | $ 327 | $ — | $ — | $ — | $ 20,617 |

(1) Includes vessel commitments the Company will utilize for certain Deepwater well intervention, drilling operations and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

(2) Includes committed purchase orders to execute planned future drilling activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

(3) Includes commitments associated with the Company's CCS Segment relating to an equity funding obligation and payments required under a sequestration agreement.

**Decommissioning Obligations**

The Company, as a co-lessee or predecessor-in-interest in oil and natural gas leases located in the U.S. Gulf of Mexico, is in the chain of title with unrelated third parties either directly or by virtue of divestiture of certain oil and natural gas assets previously owned and assigned by our subsidiaries. Certain counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Regulations or federal laws could require the Company to assume such obligations. The Company reflects such costs as "Other operating (income) expense" on the Consolidated Statements of Operations.

The decommissioning obligations included are in the Consolidated Balance Sheets as "Other current liabilities" and "Other long-term liabilities", and the changes in that liability were as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Balance, beginning of period | $ 54,269 | $ 24,336 | $ — |
| Additions | 266 | 8,900 | 21,056 |
| Changes in estimate | 11,613 | 22,658 | — |
| Reimbursements due from third parties | — | — | 3,280 |
| Settlements | (50,584) | (1,625) | — |
| Balance, end of period | $ 15,564 | $ 54,269 | $ 24,336 |
| Less: Current portion | 3,280 | 42,069 | 3,756 |
| Long-term portion | $ 12,284 | $ 12,200 | $ 20,580 |

Although it is reasonably possible that the Company could receive state or federal decommissioning orders in the future or be notified of defaulting third parties in existing leases, the Company cannot predict with certainty, if, how or when such orders or notices will be resolved or estimate a possible loss or range of loss that may result from such orders. However, the Company could incur judgments, enter into settlements or revise its opinion regarding the outcome of certain notices or matters, and such developments could have a material adverse effect on its results of operations in the period in which the amounts are accrued and its cash flows in the period in which the amounts are paid.

**Note 15 — Segment Information**

The Company's operations are managed through two operating segments: (i) Upstream Segment and (ii) CCS Segment. The Upstream Segment is the Company's only reportable segment. The Company's chief operating decision-maker ("CODM") is the President and Chief Executive Officer, who reviews operating results to make decisions about allocating resources and assessing performance for the entire company. A reportable segment is an operating segment that meets materiality thresholds. The 10% test, as prescribed by the segment reporting accounting guidance, are based on the reported measures of revenue, profit, and assets that are used by the CODM to assess performance and allocate resources. The CCS Segment currently does not meet any of the reportable segment quantitative thresholds. The profit or loss metric used to evaluate segment performance is Adjusted EBITDA, which is defined by the Company as net income (loss) plus interest expense; income tax expense (benefit); depreciation, depletion, and amortization; accretion expense; non-cash write-down of oil and natural gas properties; transaction and other (income) expenses; decommissioning obligations; the net change in the fair value of derivatives (mark to market effect, net of cash settlements and premiums related to these derivatives); (gain) loss on debt extinguishment; non-cash write-down of other well equipment; and non-cash equity-based compensation expense.

Corporate general and administrative expense include certain shared costs such as finance, accounting, tax, human resources, information technology and legal costs that are not directly attributable to each of operating segment. A portion of these expenses are allocated based on the percentage of employees dedicated to each operating segment. The remaining expenses are included in the reconciliation of reportable segment Adjusted EBITDA to consolidated pre-tax net income (loss) as an unallocated corporate general and administrative expense. The accounting policies of the segments are the same as those described in the summary of significant accounting policies.

The Company's CODM does not review assets by segment as part of the financial information provided and therefore, no asset information is provided in the table below.

The following table presents selected segment information for the periods indicated (in thousands):

| | Upstream | All Other[(1)] | Total |
|---|---|---|---|
| **Revenues from External Customers:** | | | |
| Year Ended December 31, 2023 | $ 1,457,886 | $ — | $ 1,457,886 |
| Year Ended December 31, 2022 | 1,651,980 | — | 1,651,980 |
| Year Ended December 31, 2021 | 1,244,540 | — | 1,244,540 |
| **Equity in the Net Income (Loss) of Investees Accounted for by the Equity Method:** | | | |
| Year Ended December 31, 2023 | $ 120 | $ (12,228) | $ (12,108) |
| Year Ended December 31, 2022 | 101 | (1,166) | (1,065) |
| Year Ended December 31, 2021 | — | — | — |
| **Adjusted EBITDA:** | | | |
| Year Ended December 31, 2023 | $ 979,729 | $ (22,883) | $ 956,846 |
| Year Ended December 31, 2022 | $ 859,840 | $ (12,786) | 847,054 |
| Year Ended December 31, 2021 | 615,798 | (4,782) | 611,016 |
| **Segment Expenditures:** | | | |
| Year Ended December 31, 2023 | $ 733,669 | $ 40,961 | $ 774,630 |
| Year Ended December 31, 2022 | 452,674 | 2,778 | 455,452 |
| Year Ended December 31, 2021 | 338,822 | — | 338,822 |

(1) The CCS Segment is included in the "All Other" category. The CCS Segment is an emerging business in the start-up phase of operations and the business that does not currently generate any revenues. The CCS Segment's business activities are conducted through both wholly owned subsidiaries and equity method investments with industry partners. Equity method investments is a business strategy that enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed.

**Reconciliations**

The following table presents the reconciliations of Adjusted EBITDA to the Company's consolidated totals (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| **Adjusted EBITDA:** | | | |
| Total for reportable segments | $ 979,729 | $ 859,840 | $ 615,798 |
| All other | (22,883) | (12,786) | (4,782) |
| Unallocated corporate general and administrative expense | (6,128) | (5,280) | (4,542) |
| Interest expense | (173,145) | (125,498) | (133,138) |
| Depreciation, depletion and amortization | (663,534) | (414,630) | (395,994) |
| Accretion expense | (86,152) | (55,995) | (58,129) |
| Write-down of oil and natural gas properties | — | — | (18,123) |
| Transaction and other (income) expenses[(1)] | 33,295 | 34,513 | (5,886) |
| Decommissioning obligations[(2)] | (11,879) | (31,558) | (21,055) |
| Derivative fair value gain (loss) [(3)] | 80,928 | (272,191) | (419,077) |
| Net cash (received) paid on settled derivative instruments [(3)] | 9,457 | 425,559 | 290,164 |
| Gain (loss) on extinguishment of debt | — | (1,569) | (13,225) |
| Non-cash write-down of other well equipment | — | — | (5,606) |
| Non-cash equity-based compensation expense | (12,953) | (15,953) | (10,992) |
| Income (loss) before income taxes | $ 126,735 | $ 384,452 | $ (184,587) |

(1) Transaction expenses includes $40.4 million and $9.0 million in costs related to the EnVen Acquisition, inclusive of $25.3 million and nil in severance expense for the years ended December 31, 2023 and 2022, respectively. See further discussion in Note 3 — *Acquisition and Divestitures* and Note 10 — *Employee Benefits Plans and Share-Based Compensation*. Other income (expense) includes other miscellaneous income and expenses that the Company does not view as a meaningful indicator of its operating performance. For the year ended December 31, 2023, the amount includes a $66.2 million gain on the Mexico Divestiture. See further discussion in Note 3 — *Acquisitions and Divestitures*. The amount includes a gain on the funding of the capital carry of the Company's investment in Bayou Bend by Chevron of $8.6 million and $1.4 million for the year ended December 31, 2023 and 2022, respectively. Additionally, it includes a $13.9 million gain on the partial sale of its investment in Bayou Bend to Chevron for the year ended December 31, 2022. See further discussion in Note 7 — *Equity Method Investments*. For the year ended December 31, 2022, the amount includes $27.5 million gain as a result of the settlement agreement to resolve previously pending litigation that was filed in October 2017 that is further discussed in Note 14 — *Commitments and Contingencies*.

(2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Note 14 — *Commitments and Contingencies* for additional information on decommissioning obligations.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts (payments) on settled commodity derivative instruments have the effect of adjusting net loss for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because the Company does not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on an unrealized basis during the period the derivatives settled.

The following table presents the reconciliation of Segment Expenditures to the Company's consolidated totals (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| **Segment Expenditures:** | | | |
| Total reportable segments | $ 733,669 | $ 452,674 | $ 338,822 |
| All other | 40,961 | 2,778 | — |
| Change in capital expenditures included in accounts payable and accrued liabilities | (9,199) | (60,011) | 28,258 |
| Plugging & abandonment | (86,615) | (69,596) | (67,988) |
| Decommissioning obligations settled | (50,584) | (1,625) | — |
| Investment in CCS intangibles and equity method investees | (40,946) | (2,778) | — |
| Other deferred payments | (1,545) | — | (7,921) |
| Insurance recovery proceeds | 2,802 | — | — |
| Non-cash well equipment transfers | (27,731) | (6) | 1,086 |
| Other | 622 | 1,728 | 1,074 |
| Exploration, development and other capital expenditures | $ 561,434 | $ 323,164 | $ 293,331 |

## Note 16 — Supplemental Oil and Gas Disclosures (Unaudited)

### Capitalized Costs

Aggregate amounts of capitalized costs relating to oil, natural gas and NGL activities and the aggregate amount of related accumulated depletion and amortization as of the dates indicated are presented below (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| Proved properties | $ 7,906,295 | $ 5,964,340 | $ 5,232,480 |
| Unproved oil and gas properties, not subject to amortization(1) | 268,315 | 154,783 | 219,055 |
| Total oil and gas properties | 8,174,610 | 6,119,123 | 5,451,535 |
| Less: Accumulated depletion | 4,143,491 | 3,484,590 | 3,072,907 |
| Net capitalized costs | $ 4,031,119 | $ 2,634,533 | $ 2,378,628 |
| Depletion and amortization rate (Per Boe) | $ 27.23 | $ 18.95 | $ 16.71 |
| | | | |
| ***Company's Share of Equity Investees:*** | | | |
| Unproved oil and gas properties, not subject to amortization | $ 56,579 | $ — | $ — |

(1) Amount includes $111.4 million and $110.3 million of unproved properties, not subject to amortization, related to the Company's operations in offshore Mexico for the years ended December 31, 2022 and 2021, respectively.

Included in the depletable basis of proved oil and gas properties is the estimate of the Company's proportionate share of asset retirement costs relating to these properties which are also reflected as "Asset retirement obligations" on the accompanying Consolidated Balance Sheets. See Note 9 — *Asset Retirement Obligations* for additional information.

### Costs Incurred for Property Acquisition, Exploration and Development Activities

The following table reflects the costs incurred in oil, natural gas and NGL property acquisition, exploration and development activities during the years indicated (in thousands). Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to estimates during the year.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| Property acquisition costs: | | | |
| Proved properties | $ 951,703 | $ — | $ 210 |
| Unproved properties, not subject to amortization | 249,688 | 2,221 | — |
| Total property acquisition costs | 1,201,391 | 2,221 | 210 |
| Exploration costs(1) | 161,296 | 125,889 | 23,844 |
| Development costs | 805,148 | 541,512 | 245,058 |
| Total costs incurred | $ 2,167,835 | $ 669,622 | $ 269,112 |
| | | | |
| ***Company's Share of Equity Investees:*** | | | |
| Exploration costs | $ 290 | $ — | $ — |

(1) Amount includes nil, $1.2 million and $6.6 million of exploration costs related to the Company's operations in offshore Mexico for the years ended December 31, 2023, 2022 and 2021, respectively.

### Estimated Quantities of Proved Oil, Natural Gas and NGL Reserves

The Company employs full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The reserve data in the following tables only represent estimates and should not be construed as being exact. Engineering reserve estimates were prepared based upon interpretation of production performance data and subsurface information obtained from the drilling of existing wells. The Company's Director of Reserves, internal reservoir engineers and geologists analyzed and prepared reserve estimates on all oil and natural gas fields. All of the Company's proved oil, natural gas and NGL reserves are located in the U.S. Gulf of Mexico.

At December 31, 2023, 2022 and 2021, 100% of proved oil, natural gas and NGL reserves attributable to all of the Company's oil and natural gas properties were estimated and compiled for reporting purposes by the Company's reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists.

The following table presents the Company's estimated proved reserves at its net ownership interest:

| | Oil (MBbls) | Gas (MMcf) | NGL (MBbls) | Oil Equivalent (MBoe) |
|---|---|---|---|---|
| ***Consolidated Entities:*** | | | | |
| Total proved reserves at December 31, 2020 | 109,307 | 257,208 | 10,858 | 163,033 |
| Revision of previous estimates | 13,619 | 8,979 | 5,137 | 20,252 |
| Production | (16,159) | (32,795) | (1,875) | (23,500) |
| Extensions and discoveries | 997 | 2,961 | 315 | 1,806 |
| Total proved reserves at December 31, 2021 | 107,764 | 236,353 | 14,435 | 161,591 |
| Revision of previous estimates | (5,625) | (8,302) | (2,002) | (9,010) |
| Production | (14,561) | (32,215) | (1,793) | (21,723) |
| Sales of reserves | (158) | (7,625) | — | (1,429) |
| Extensions and discoveries | 3,639 | 31,340 | 2,288 | 11,150 |
| Total proved reserves at December 31, 2022 | 91,059 | 219,551 | 12,928 | 140,579 |
| Revision of previous estimates | (6,308) | (62,946) | (1,283) | (18,082) |
| Production | (18,062) | (26,194) | (1,767) | (24,195) |
| Purchases of reserves | 41,871 | 36,690 | 1,116 | 49,102 |
| Extensions and discoveries | 2,255 | 12,770 | 979 | 5,362 |
| Total proved reserves at December 31, 2023 | 110,815 | 179,871 | 11,973 | 152,766 |
| **Total Proved Developed Reserves as of:** | | | | |
| December 31, 2021 | 93,420 | 186,442 | 11,792 | 136,286 |
| December 31, 2022 | 80,285 | 161,727 | 9,315 | 116,555 |
| December 31, 2023 | 98,225 | 141,823 | 9,957 | 131,819 |
| **Total Proved Undeveloped Reserves as of:** | | | | |
| December 31, 2021 | 14,344 | 49,911 | 2,643 | 25,305 |
| December 31, 2022 | 10,774 | 57,824 | 3,613 | 24,024 |
| December 31, 2023 | 12,590 | 38,048 | 2,016 | 20,947 |

During 2023, proved reserves increased by 12.2 MMBoe primarily due to a purchases of reserves of 49.1 MMBoe in connection with the EnVen Acquisition and 5.4 MMBoe of estimated proved reserves from extensions and discoveries primarily from evaluations of the Brutus Field in the Green Canyon core area. This increase was partially offset by a decrease of 24.2 MMBoe of production and a decrease of 18.1 MMBoe from revisions of previous estimates. The revisions were primarily due to a 13.5 MMBoe decrease in reserve volumes due to the decrease in SEC Pricing of $17.47 per Bbl of oil and $4.05 per Mcf of natural gas and an additional decrease in the Phoenix Field in the Green Canyon core area due to well performance.

During 2022, proved reserves decreased by 21.0 MMBoe primarily due to a decrease of 21.7 MMBoe of production. Additionally, there was a decrease of 9.0 MMBoe primarily due to timing of development of certain PUD locations to move beyond five years at the Phoenix Field in the Green Canyon core area and sales of reserves of 1.4 MMBoe primarily related to the Brushy Creek Field in the Shelf and Gulf Coast area. The decrease was partially offset by 11.2 MMBoe of estimated proved reserves from extensions and discoveries primarily from evaluations of the Pompano Field and the Ram Powell Field located in the Mississippi Canyon core area.

During 2021, proved reserves decreased by 1.4 MMBoe primarily due to a decrease of 23.5 MMBoe of production. The decrease was partially offset by revision to previous estimates of 20.3 MMBoe due to increase in commodity prices as well as 1.8 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Crown and Anchor Field located in the Mississippi Canyon core area.

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves**

The following table reflects the standardized measure of discounted future net cash flows relating to the Company's interest in proved oil, natural gas and NGL reserves (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| Future cash inflows | $ 9,425,055 | $ 10,674,896 | $ 8,496,005 |
| Future costs: | | | |
| Production | (3,090,491) | (1,906,752) | (1,868,818) |
| Development and abandonment | (2,358,368) | (1,873,453) | (1,422,507) |
| Future net cash flows before income taxes | 3,976,196 | 6,894,691 | 5,204,680 |
| Future income tax expense | (589,413) | (1,114,409) | (676,778) |
| Future net cash flows after income taxes | 3,386,783 | 5,780,282 | 4,527,902 |
| Discount at 10% annual rate | (343,295) | (1,411,834) | (1,087,291) |
| Standardized measure of discounted future net cash flows | $ 3,043,488 | $ 4,368,448 | $ 3,440,611 |

Future cash inflows are computed by applying SEC Pricing to year-end quantities of proved reserves. The discounted future cash flow estimates do not include the effects of derivative instruments. See the following table for SEC Pricing used in determining the standardized measure:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Oil price per Bbl | $ 78.56 | $ 96.03 | $ 67.14 |
| Natural gas price per Mcf | $ 2.75 | $ 6.80 | $ 3.71 |
| NGL price per Bbl | $ 18.77 | $ 33.89 | $ 26.62 |

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development and abandonment costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. All estimated costs to settle asset retirement obligations associated with the Company's proved reserves have been included in their calculation of development and abandonment of the standardized measure of discounted future net cash flows for each period presented. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

**Changes in Standardized Measure of Discounted Future Net Cash Flows**

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil, natural gas and NGL reserves are as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| ***Consolidated Entities:*** | | | |
| Standardized measure, beginning of year | $ 4,368,448 | $ 3,440,611 | $ 1,904,934 |
| Sales and transfers of oil, net gas and NGLs produced during the period | (1,065,814) | (1,340,400) | (957,576) |
| Net change in prices and production costs | (2,835,125) | 2,388,442 | 2,049,980 |
| Changes in estimated future development and abandonment costs | (19,877) | (84,391) | (57,876) |
| Previously estimated development and abandonment costs incurred | 202,503 | 20,107 | 69,125 |
| Accretion of discount | 518,110 | 392,600 | 199,849 |
| Net change in income taxes | 357,321 | (327,265) | (391,834) |
| Purchases of reserves | 2,033,852 | — | — |
| Sales of reserves | — | (5,218) | — |
| Extensions and discoveries | 90,244 | 202,239 | 45,485 |
| Net change due to revision in quantity estimates | (484,423) | (255,743) | 426,357 |
| Changes in production rates (timing) and other | (121,751) | (62,534) | 152,167 |
| Standardized measure, end of year | $ 3,043,488 | $ 4,368,448 | $ 3,440,611 |

**Note 17 — Subsequent Events**

**QuarterNorth Acquisition**

For additional Information, see the following:

- Note 3 — *Acquisitions and Divestitures*
- Note 8 — *Debt*
- Note 13 — *Related Party Transactions*

**Equity Offering**

On January 22, 2024, the Company closed an upsized underwritten public offering (the "January Equity Offering") of 34.5 million shares of the Company's common stock, resulting in net proceeds to the Company of approximately $388.5 million, after deducting underwriting discounts and commissions and before estimated offering expenses. The Company intends to use the net proceeds from the January Equity Offering to fund a portion of the cash consideration for the QuarterNorth Acquisition. However, the QuarterNorth Acquisition remains subject to certain conditions to closing. Pending the use of the proceeds of the January Equity Offering as described above, the Company may temporarily use all or a portion of such proceeds to reduce the borrowings outstanding under the Company's Bank Credit Facility. In the event that the QuarterNorth Acquisition is not completed, the proceeds from the January Equity Offering will be used for general corporate purposes.

## Schedule I. Condensed Financial Information of Registrant

### TALOS ENERGY INC. (PARENT ONLY)
### BALANCE SHEETS
### (In thousands, except share amounts)

| | Year Ended December 31, 2023 | Year Ended December 31, 2022 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Accounts receivable: | | |
| Other, net | $ 100 | $ — |
| Prepaid assets | 221 | 169 |
| Other current assets | 19 | 36 |
| Total current assets | 340 | 205 |
| Other long-term assets: | | |
| Investments in subsidiaries | 2,246,908 | 1,168,053 |
| **Total assets** | $ 2,247,248 | $ 1,168,258 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 316 | $ 249 |
| Accrued liabilities | 705 | 728 |
| Other current liabilities | 124 | 62 |
| Total current liabilities | 1,145 | 1,039 |
| Long-term liabilities: | | |
| Other long-term liabilities | 90,952 | 1,643 |
| Total liabilities | 92,097 | 2,682 |
| Commitments and contingencies | | |
| Stockholders' equity: | | |
| Preferred stock; $0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of December 31, 2023 and 2022, respectively | — | — |
| Common stock; $0.01 par value; 270,000,000 shares authorized; 127,480,361 and 82,570,328 shares issued as of December 31, 2023 and 2022, respectively | 1,275 | 826 |
| Additional paid-in capital | 2,549,097 | 1,699,799 |
| Accumulated deficit | (347,717) | (535,049) |
| Treasury stock, at cost; 3,400,000 and zero shares as of December 31, 2023 and 2022, respectively | (47,504) | — |
| Total stockholders' equity | 2,155,151 | 1,165,576 |
| **Total liabilities and stockholders' equity** | $ 2,247,248 | $ 1,168,258 |

See accompanying notes.

# TALOS ENERGY INC. (PARENT ONLY)
# STATEMENTS OF OPERATIONS
# (In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Revenues: | | | |
| Oil | $ — | $ — | $ — |
| Natural gas | — | — | — |
| NGL | — | — | — |
| Total revenues | — | — | — |
| Operating expenses: | | | |
| Lease operating expense | — | — | — |
| Production taxes | — | — | — |
| Depreciation, depletion and amortization | — | — | — |
| Accretion expense | — | — | — |
| General and administrative expense | $ 2,708 | $ 2,145 | $ 1,322 |
| Other operating (income) expense | — | — | — |
| Total operating expenses | 2,708 | 2,145 | 1,322 |
| Operating income (expense) | (2,708) | (2,145) | (1,322) |
| Interest expense | — | — | (5) |
| Price risk management activities income (expense) | — | — | — |
| Equity method investment income (expense) | — | — | — |
| Other income (expense) | (1) | (1) | (2) |
| Equity earnings (loss) from subsidiaries | 128,888 | 385,968 | (180,548) |
| Net income (loss) before income taxes | 126,179 | 383,822 | (181,877) |
| Income tax benefit (expense) | 61,153 | (1,907) | (1,075) |
| **Net income (loss)** | $ 187,332 | $ 381,915 | $ (182,952) |

See accompanying notes.

## TALOS ENERGY INC. (PARENT ONLY)
## STATEMENTS OF CASH FLOWS
## (In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2023 | 2022 | 2021 |
| Cash flows from operating activities: | | | |
| Net cash provided by (used in) operating activities | $ (1,836) | $ (809) | $ (876) |
| Cash flows from investing activities: | | | |
| Distributions from subsidiaries | 49,340 | 809 | 879 |
| Contributions to subsidiaries | — | — | (3) |
| Net cash provided by (used in) investing activities | 49,340 | 809 | 876 |
| Cash flows from financing activities: | | | |
| Purchase of treasury stock | (47,504) | — | — |
| Net cash provided (used in) by financing activities | (47,504) | — | — |
| | | | |
| Net increase (decrease) in cash and cash equivalents | — | — | — |
| Cash and cash equivalents: | | | |
| Balance, beginning of period | — | — | — |
| Balance, end of period | $ — | $ — | $ — |

See accompanying notes.

**TALOS ENERGY INC. (PARENT ONLY)**
**NOTES TO CONDENSED FINANCIAL STATEMENTS**
**December 31, 2023**

**Note 1 — Basis of Presentation**

Pursuant to the rules and regulations of the SEC, the parent only condensed financial information of Talos Energy, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read in conjunction with the consolidated financial statements and related notes included under Part IV, Item 15. Exhibits and Financial Statement Schedules in this Annual Report.

Back: Megan Dick, C. Gordon Lendsey, Deborah Huston, Greg Babcock, Joe Sauvageau, Joel Plauche
Front: Sergio Maiworm, William S. Moss III, John A. Parker, Timothy S. Duncan, John B. Spath

## MANAGEMENT TEAM

**TIMOTHY S. DUNCAN**
President and Chief Executive Officer

**JOHN A. PARKER**
Executive Vice President, New Ventures

**WILLIAM S. MOSS III**
Executive Vice President, General Counsel and Secretary

**JOHN B. SPATH**
Executive Vice President and Head of Operations

**SERGIO L. MAIWORM JR.**
Senior Vice President and Chief Financial Officer

**GREG BABCOCK**
Vice President and Chief Accounting Officer

**MEGAN DICK**
Vice President, Human Resources

**DEBORAH HUSTON**
Vice President and Deputy General Counsel

**C. GORDON LINDSEY**
Vice President, Corporate Development

**JOE SAUVAGEAU**
Vice President, Asset Development

**JOEL PLAUCHE**
Vice President, HSE, Regulatory and Compliance

## BOARD OF DIRECTORS

**NEAL P. GOLDMAN**
Chairman of the Board
Managing Member, SAGE Capital Investments, LLC

**TIMOTHY S. DUNCAN**
President and Chief Executive Officer, Talos Energy Inc.

**PAULA R. GLOVER**
President, Alliance to Save Energy

**JOHN "BRAD" JUNEAU**
Sole Manager and General Partner, Juneau Exploration, L.P.

**DONALD R. KENDALL, JR.**
Director and Chief Executive Officer, Kenmont Capital Partners

**JOSEPH A. MILLS**
Chief Executive Officer, Samson Resources II, LLC &
Founder/Owner, Waterford Energy, LLC

**RICHARD SHERRILL**
President, Clean Aire Partners

**CHARLES M. SLEDGE**
Retired Chief Financial Officer, Cameron International

**SHANDELL SZABO**
Retired Vice President of U.S. Exploration, Anadarko Petroleum Corporation

## STOCKHOLDER INFORMATION

**CORPORATE OFFICE**
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713.328.3000

**WEBSITE**
www.talosenergy.com

**STOCK EXCHANGE LISTING**
New York Stock Exchange
Symbol: TALO

**ANNUAL MEETING**
May 23, 2024 at 10:00 AM CT
Three Allen Center
333 Clay St., Suite 3300
Houston, TX 77002

**FORM 10-K**
Copies of the corporation's 10-K are available on our website at www.talosenergy.com

**AUDITORS**
Ernst & Young
Houston, TX

**SHAREHOLDER SERVICES**
Computershare
P.O. Box 505000
Louisville, KY 40233
Toll-Free: 1.800.962.4284
International: 1.781.575.3120

**OVERNIGHT MAIL**
462 South 4th Street, Suite 1600Louisville, KY 40202

**INVESTOR RELATIONS**
Contact us at investor@talosenergy.com

TALOS ENERGY

THINK AS AN OWNER

EMBODY INTEGRITY AND SAFETY

MAINTAIN OPTIONALITY

EMPOWER EACH OTHER

EMBRACE DIVERSITY AND INCLUSION

333 Clay St., Suite 3300
Houston, Texas 77002

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