TALOS ENERGY

2024
ANNUAL REPORT

TALOS ENERGY

is a technically driven, innovative, independent energy company focused on maximizing long-term value through our oil and gas exploration and production business in the United States Gulf of America (GOA) and offshore Mexico.

We leverage decades of technical and offshore operational expertise to acquire, explore, and produce assets in key geological trends while maintaining a focus on safe and efficient operations, environmental responsibility and community impact.

About Talos

700 Employees[1]

5TH LARGEST Operator in the GOA[2]

5TH LARGEST Acreage Holder in the GOA[2]

Key Metrics

92.6 MBOE/D Average Daily Production[1]

$1,288 MILLION Adjusted EBITDA[1][3]

$604 MILLION Upstream Capital Investment[1][4]

Responsibility

ESG Rating of **A** by **MSCI** since May 2023

~**26% REDUCTION** in Scope 1 GHG Emissions Intensity vs 2018 Baseline[5]

~**56% REDUCTION** in Scope 2 GHG Emissions vs 2018[6]

Safety

In 2024, Talos achieved continued success in safety performance, finishing the year with a Total Recordable Incident Rate significantly below the GOA industry average for the past four years while working approximately 6.6 million man-hours. For regulatory compliance, we were in-line with the GOA industry average for production operations, while our drilling operations continued to outperform the industry. This success reflects our field personnel's commitment to rigorous safety system testing, proactive facility maintenance, and dedication to upholding the highest operational standards at Talos.

(1) Reflects Talos for year ended December 31, 2024.
(2) Operator data based on GOMSmart and BSEE utilizing 2024 reported figures. Acreage data per GOM-Cubed. Acreage figures as of December 31, 2024.
(3) Adjusted EBITDA is a non-GAAP financial measure. Please refer to "MD&A and Results of Operations--Supplemental Non-GAAP Measure" located in our 2024 Annual Report (the "Annual Report") for a reconciliation of GAAP to non-GAAP financial measures.
(4) Upstream Capital Investments include plugging and abandonment and settlement and decommissioning obligations.
(5) Reduction was calculated from 2018 to 2023. Scope 1 GHG emissions intensity includes EnVen and QuarterNorth data as if owned the entire time and baselined to 2018. See 2024 Sustainability Report pg 31 for more details, which can be located on our website at www.talosenergy.com. Information included in our Sustainability Report or information on our website (other than U.S. Securities and Exchange Commission ("SEC") reports that are expressly incorporated by reference in our Annual Report) is not incorporated into this Annual Report or any other report or document we file with the SEC.
(6) Reduction was calculated from 2018 to 2023. Scope 2 reduction is historical Talos only assets prior to 2022. EnVen and QuarterNorth did not calculate Scope 2 emission prior to 2022. See 2024 Sustainability Report pg 30 for more details, which can be located on our website at www.talosenergy.com. Information included in our Sustainability Report or information on our website (other than U.S. Securities and Exchange Commission ("SEC") reports that are expressly incorporated by reference in our Annual Report) is not incorporated into this Annual Report or any other report or document we file with the SEC.

2024 and Recent Highlights

Talos has a dedicated management team and employee base, which have remained focused on our operating performance, achieving strong financial results, and executing our strategic objectives.
Our results in 2024, and Talos's position going forward, are a direct result of our employees' hard work and commitment to excellence.

TALOS ENERGY

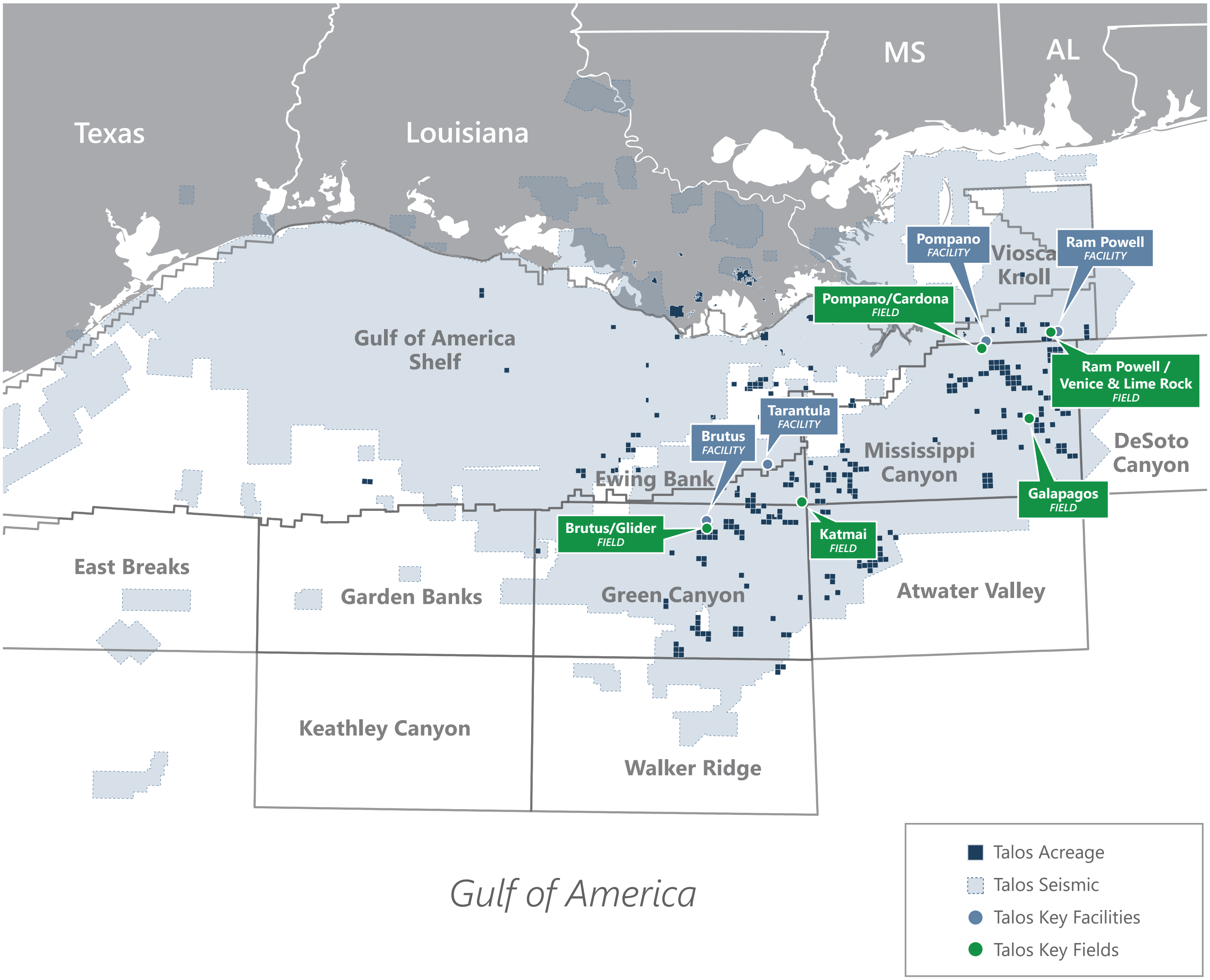
Delivering Operationally

- Consistently beat quarterly Wall Street[1] consensus on production
- Achieved record production of 92.6 MBOE/D[2]
- Successfully drilled the Katmai West #2 well a month faster than expected and approximately 35% under budget
- Acquired a 21.4% working interest (W.I.) in the Monument discovery in the GOA and increased W.I. to 29.76% in early 2025
- Made commercial discovery at Ewing Bank 953
- Achieved continued success with a Total Recordable Incident Rate of 0.36, significantly below the GOA industry average of 0.51, while working 6.6 million man-hours

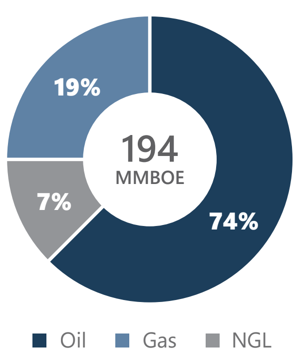
Delivering Financially

- Consistently beat quarterly Wall Street consensus on Adjusted EBITDA[1] and Adjusted Free Cash Flow[1]
- Achieved Adjusted EBITDA[3] of $1,288 million
- Increased scale of Talos with the QuarterNorth acquisition and captured more synergies than expected
- Refinanced our bonds, allowing us to extend maturities and reduce interest rates
- Reduced debt by $550 million under Talos's credit facility, resulting in no borrowings by year-end 2024 and achieving our lowest leverage ratio
- Repurchased approximately 4 million shares of Talos's common stock for $45 million

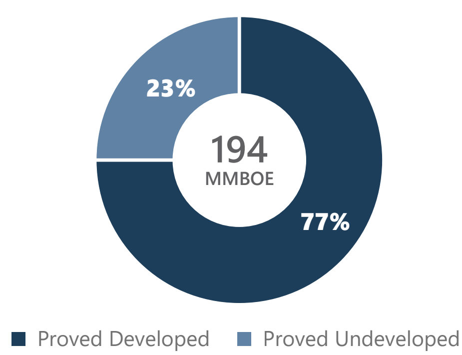
(1) Quarterly Wall Street consensus per Factset.
(2) Reflects Talos for year ended December 31, 2024.
(3) Adjusted EBITDA is a non-GAAP financial measure. Please refer to "MD&A and Results of Operations--Supplemental Non-GAAP Measure" located in our 2024 Annual Report (the "Annual Report") for a reconciliation of GAAP to non-GAAP financial measures.



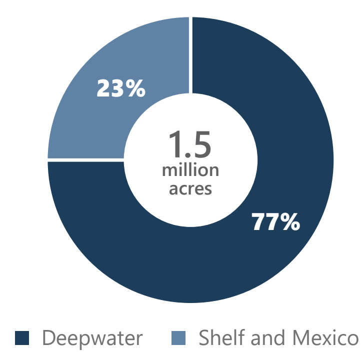
PROVED RESERVES PRODUCT MIX



PROVED RESERVES CATEGORY MIX



DEEPWATER FOOTPRINT



Notes: This data summarizes year-end 2024 reserves. 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 $76.32 WTI per BBL of oil and $2.13 HH per MMBtu of natural gas. Acreage figures as of December 31, 2024. 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.

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, 2024

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 **(State or other jurisdiction of incorporation or organization)**	**82-3532642** **(I.R.S. Employer Identification No.)**
333 Clay Street, Suite 3300 **Houston, TX** **(Address of principal executive offices)**	**77002** **(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 28, 2024, was $1,529,482,022.

The number of shares of registrant's Common Stock outstanding as of February 19, 2025 was 180,059,531.

Portions of the registrant's definitive proxy statement relating to the 2025 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

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.

***Dry well* —** A well that is an exploratory or development well that is not a productive well.

***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;
- estimated or recoverable resources and reserves;
- drilling prospects, inventories, projects and programs;
- our ability to replace the reserves that we produce through drilling and acquisitions;
- financial strategy, borrowing base under our Bank Credit Facility, availability of financing sources, liquidity and capital required for our development program, acquisitions and other capital expenditures;
- realized oil and natural gas prices;
- unexpected changes in tariffs, trade barriers, price and exchange controls and other regulatory requirements, including such changes that may be implemented by the Trump Administration;
- volatility in the political, legal and regulatory environments in connection with the U.S. and Mexican presidential transitions;
- risks related to future mergers and acquisitions, including the risk that we may fail 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 plans;
- availability of pipeline connections on economic terms;
- competition, government regulations, including financial assurance requirements, and legislative and political developments;
- our ability to obtain permits and governmental approvals, including the timing and potential impact of the anticipated revised Gulf of America biological opinion by the National Marine Fisheries Services;
- pending legal, governmental or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our integration of acquisitions and the anticipated 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;
- 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;
- our strategy with respect to our investment in the Zama asset, of which PEMEX is the operator;
- 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 Israel and 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; political risks, including a potential trade war with Mexico and/ or Canada; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes, winter storms and loop currents; cybersecurity threats; 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, including the impact of financial assurance requirements; changes in U.S. trade policy, including the imposition of tariffs and resulting consequences; 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; 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 America 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.
- 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.
- Recent and pending management changes could disrupt our operations and impair our ability to attract and retain key personnel.
- 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 provide the financial assurances in sufficient amounts or on reasonably acceptable terms to comply with regulatory requirements, or otherwise, in order to conduct our business in the OCS.
- Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.
- We may not be in a position to control the timing of development efforts, 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.
- Our ability to obtain permits and governmental approvals for our U.S. Gulf of America operations may be delayed by the court-mandated vacatur of the National Marine Fisheries Services' Gulf of America Biological Opinion if NMFS is unable to publish a revised biological opinion by the vacatur date.
- 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, winter storms and hurricanes in the U.S. Gulf of America and in the shallow waters off the coast of Mexico and epidemics, outbreaks or other public health events.
- We have entered into certain agreements which contain minimum volume commitments. Any failure by us to satisfy these commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.

- 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.
- Changes in U.S. trade policy, including the imposition of tariffs and the resulting consequences, could adversely affect our business, prospects, financial condition and operating results.
- We previously identified material weaknesses in our internal control over financial reporting that could have, had they not been remediated, resulted in material misstatements in our financial statements and caused us to fail to meet our reporting and financial obligations.

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 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 interests of the Slim Family and its affiliates may differ from the interests of our other stockholders.
- 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 assets and future acquisitions, and we may be unable to successfully integrate future acquisitions.
- Our current assets and future acquisitions expose us to potentially significant liabilities, including P&A liabilities.
- Resolution of litigation could materially affect our financial position and results of operations.
- Actions of any activist stockholders or others could materially and adversely affect our business, results of operations and stock price.

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 (the “NYSE”) under the symbol “TALO.”

We are a technically driven, innovative, independent energy company focused on maximizing long-term value through our oil and gas exploration and production (“Upstream”) business in the United States (“U.S.”) Gulf of America and offshore Mexico. We leverage decades of technical and offshore operational expertise to acquire, explore, and produce assets in key geological trends while maintaining a focus on safe and efficient operations, environmental responsibility and community impact.

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 oil, natural gas and NGL reserves, production, cash flow and future acquisition opportunities in a disciplined and capital efficient manner. Our deep technical expertise and extensive operating experience also allows us to successfully manage our business and consistently make attractive acquisitions.

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 America and offshore Mexico, allows our technical team to apply proprietary seismic reprocessing techniques to evaluate or re-evaluate and identify potential resources and new opportunities 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 America 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 assets 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 U.S. Gulf of America continues to provide some of the lowest greenhouse gas (“GHG”) emissions intensity due to the nature of subsea wells and established offshore pipelines 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.

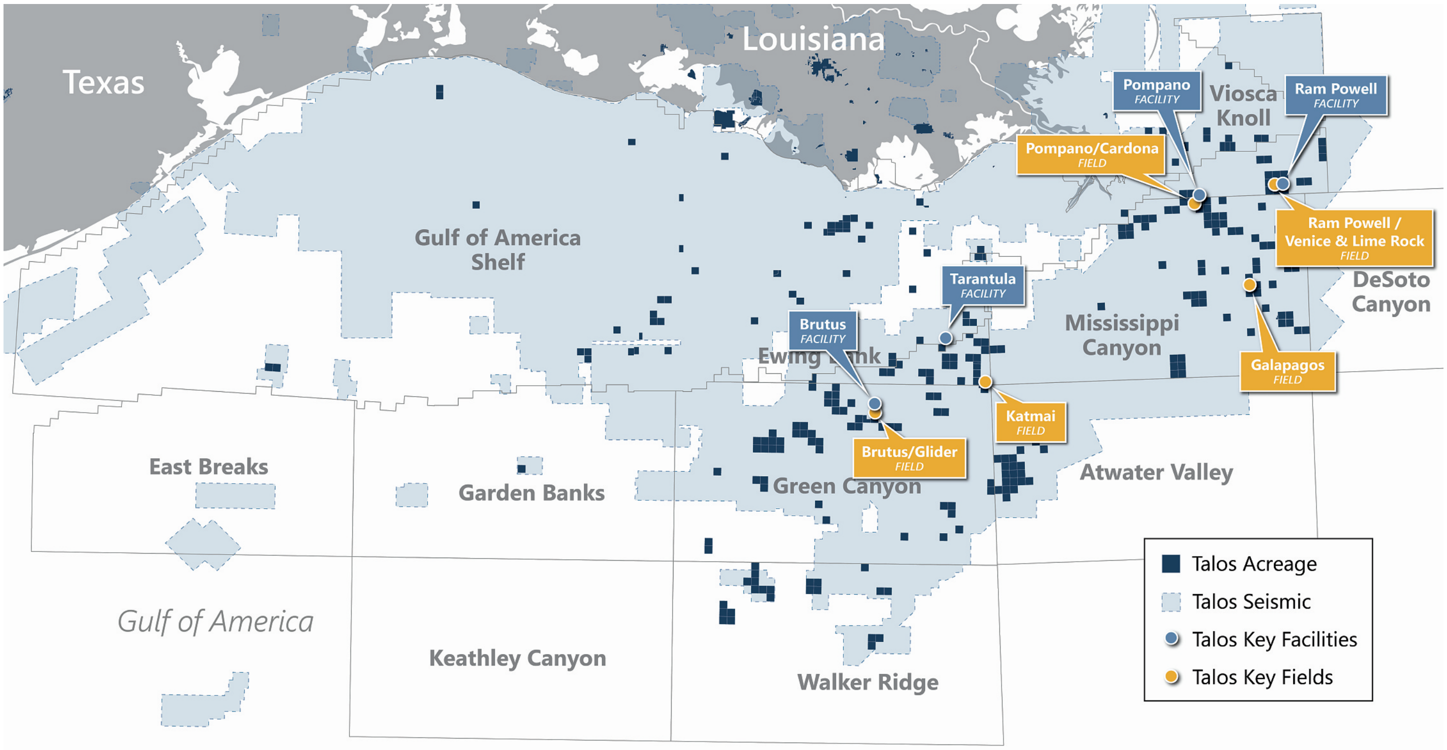
Properties

U.S. Gulf of America

Our area of focus in the U.S. is the Gulf of America Deepwater. We concentrate 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 America 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 an 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, 2024, our acreage, seismic and key facilities and fields in the U.S. are summarized in the illustration below:



The following table sets forth a summary of certain key 2024 information regarding our areas of operation in the U.S.:

	Estimated Proved Reserves						
	MBoe	% Oil	% Natural Gas	% NGLs	% Proved Developed	Net Production (MBoe)	% Operated
Deepwater	173,781	77 %	15 %	8 %	77 %	29,165	86 %
Shelf & Gulf Coast	20,461	43 %	46 %	11 %	79 %	4,728	70 %
Total United States	194,242	74 %	19 %	7 %	77 %	33,893	83 %

Deepwater — The Deepwater region in the Central U.S. Gulf of America remains a vital industry and a core focus area for our exploration, development and operational activities. This region has a history of prolific production and ongoing exploration success, with further opportunities to unlock additional resources. Our key fields in the Deepwater region include the following:

- ***Katmai*** — The Katmai Field was acquired through our acquisition of QuarterNorth Energy Inc. ("QuarterNorth"), a privately-held U.S. Gulf of America exploration and production company (the "QuarterNorth Acquisition") and comprises four operated blocks including Ewing Bank Blocks 1009 and 1010 and Green Canyon Blocks 39 and 40. We recently drilled the Katmai West #2 well, an appraisal well that encountered over 400 feet of gross hydrocarbon pay. The Katmai Field is tied back to our wholly owned Tarantula production facility.

- ***Pompano / Cardona*** — The Pompano Field is comprised of eight operated blocks, which include Viosca Knoll Blocks 989 and 990 and Mississippi Canyon Blocks 26, 27, 28, 29, 72 and 73. The Pompano Field has two operated subsea systems and two outside operated systems that are tied back to our wholly owned Pompano production facility.

- ***Brutus / Glider*** — The Brutus Field is comprised of three operated blocks, which include Green Canyon Blocks 158, 202, and 248. The Brutus field has one operated subsea system (Glider) and one outside operated subsea system that is tied back to our wholly owned Brutus facility.

- ***Ram Powell / Venice & Lime Rock*** — The Ram Powell Field is comprised of eight operated blocks, which include Viosca Knoll Blocks 911, 912, 913, 955, 956, 957, 1000, and 1001. The Ram Powell field has two operated subsea systems that process the recent near-field discoveries Venice and Lime Rock and one outside operated subsea system, which are tied back to our wholly owned Ram Powell facility.

- ***Galapagos*** — The Galapagos Field is comprised of the operated Mississippi Canyon Block 519. The Galapagos subsea system is tied back to a non-operated facility.

Shelf and Gulf Coast — The U.S. Gulf of America 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

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.

In 2015, Mexico's upstream oil and gas regulator, the National Hydrocarbon Commission ("CNH") awarded a Talos-led consortium ("Block 7 Consortium") a production sharing contract ("PSC") covering Block 7 with a term of thirty years, extendable for two additional five-year periods. Talos, through Talos Energy Mexico 7, S. de R.L. de C.V. ("Talos Mexico"), was named operator of Block 7. The Block 7 Consortium made a significant discovery in Block 7 after drilling the Zama-1 in 2017.

After drilling three additional wells, Mexico's Secretaría de Energía ("SENER") determined that the hydrocarbons extended into a nearby offshore block assigned to Petróleos Mexicanos ("PEMEX") and unitized our PSC contract area with PEMEX's Assignation and designated PEMEX as Operator of the Zama unit. The Block 7 Consortium holds 49.6% of the gross interest in the Zama Field with PEMEX holding 50.4%. In June 2023, CNH approved a Zama Unit Development Plan, which was further modified in 2024 to reflect infrastructure development timelines.

On September 27, 2023, we sold a 49.9% equity interest in Talos Mexico to Zamajal, S.A. de C.V. ("Zamajal"), an entity owned 90% by Grupo Carso, S.A.B. de C.V. ("Carso") and 10% by Control Empresarial de Capitales, S.A. de C.V. ("Control Empresarial") (the "2023 Mexico Divestiture").Control Empresarial, an entity controlled by the family of Carlos Slim Helú, is a beneficial owner of approximately 24% of the outstanding shares of the Company's common stock. On December 16, 2024, we entered into an agreement to sell an additional 30.1% equity interest in Talos Mexico to Zamajal, a subsidiary of Carso, for $49.7 million in cash consideration with an additional $33.1 million contingent on first oil production from the Zama Field (the "Incremental Mexico Equity Sale"). The Incremental Mexico Equity Sale is expected to close during 2025 upon the satisfaction of customary closing conditions and the receipt of all regulatory approvals. After consummation of the Incremental Mexico Equity Sale, Talos Mexico, which currently holds a 17.4% interest in the Zama field, will be owned 20.0% by the Company and 80.0% by Zamajal. While the Company anticipates the Incremental Mexico Equity Sale will close in 2025, there can be no assurance that all of the conditions to closing, including obtaining necessary regulatory approvals, will be satisfied. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* and Note 7 — *Equity Method Investments* for additional information on the Incremental Mexico Equity Sale and Note 14 — *Related Party Transactions* for additional information on Carso.

Summary of Reserves

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

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe	Standardized Measure (in thousands)	PV -10 (in thousands)
Consolidated Entities:						
December 31, 2024						
Proved developed producing	82,687	108,041	8,279	108,973		$ 2,875,948
Proved developed non-producing	25,792	67,098	4,454	41,429		715,006
Total proved developed	108,479	175,139	12,733	150,402		3,590,954
Proved undeveloped	34,569	42,835	2,132	43,840		609,770
Total proved	143,048	217,974	14,865	194,242	$ 3,564,204	$ 4,200,724
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

See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 17 — *Supplemental Oil and Gas Disclosures (Unaudited)* for additional information on our estimated proved reserves and standardized measure.

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,		
	2024	2023	2022
Consolidated Entities:			
Standardized measure	$ 3,564,204	$ 3,043,488	$ 4,368,448
Present value of future income taxes discounted at 10%	636,520	455,330	812,651
PV-10 (Non-GAAP)	$ 4,200,724	$ 3,498,818	$ 5,181,099

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, 2023	20,947	$ 284,756
Changes during the year:		
Extensions and discoveries	7,328	213,389
Revisions of previous estimates	(13,113)	(246,646)
Acquired	32,603	667,590
Conversion to proved developed	(3,925)	(37,907)
Total proved undeveloped reserves changes	22,893	596,426
Proved undeveloped reserves at December 31, 2024	43,840	$ 881,182

Our PUD reserves at December 31, 2024 increased by 22.9 MMBoe, or 109% primarily due to:

Extensions and Discoveries — Extensions and discoveries of 7.3 MMBoe are primarily attributable to 3.3 MMBoe from the successful drilling of the Sunspear well and a non-operated well in our Ewing Bank 953 Field along with new PUD reserves in our Brutus Field and Pompano Field, all located in the Deepwater area.

Revisions of Previous Estimates — Downward revisions of 13.1 MMBoe are due to approximately 6.1 MMBoe of revisions in Brutus Field and Prince Field in the Deepwater area becoming uneconomic under current conditions. Additionally, due to the Deepwater assets acquired via the QuarterNorth Acquisition and the Monument oil discovery ("Monument Project"), we reassessed our drilling and development plan resulting in derecognition of 4.2 MMBoe of PUD reserves primarily associated with non-operated fields located in our Shelf and Gulf Coast area.

Acquired — Acquired PUD reserves of 32.6 MMBoe is comprised of 21.0 MMBoe attributable to the QuarterNorth Acquisition primarily located in the Deepwater area and 11.6 MMBoe attributable to the acquisition of a non-operated working interest in the Monument Project in the Deepwater area. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

Conversion to Proved Developed — Conversions of 3.9 MMBoe are primarily attributable to the completion of the waterflood well in our Lobster Field located in the Deepwater 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, 2024 totaled approximately $881.2 million, of which $831.6 million, and $49.6 million is attributable to our Deepwater and Shelf and Gulf Coast areas, respectively. When considering capital expenditures associated with 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 2025 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, 2024, all proved reserves were estimated by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists. At December 31, 2023 and 2022, 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 NSAI 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;
- 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 when the reserves audit was conducted for the years ended December 31, 2023 and 2022, 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.

NSAI estimated our proved reserves at December 31, 2024 using deterministic methods. The estimates were prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPEE. NSAI used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that they considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. The data used in NSAI's estimates were obtained from us, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. The NSAI report at December 31, 2024 includes the professional qualifications for the technical persons primarily responsible for preparing the estimated proved reserves and is filed as Exhibit 99.1 to this Annual Report.

NSAI issued unqualified audit opinions on our reserves as of December 31, 2023 and 2022 based upon its evaluations. NSAI concluded that our estimates of reserves were, in the aggregate, reasonable and were prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPEE.

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

With over 30 years of industry experience, the Company's Director of Reserves is the technical person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating engagements conducted by NSAI. She holds a bachelor's degree in civil engineering from Rafael Urdaneta University in Venezuela and a Master of Science in Petroleum Engineering from the University of Zulia in Venezuela. She worked as a reservoir and simulation engineer for Petróleos de Venezuela S.A. for 12 years before relocating to the Houston, Texas area. Prior to joining Talos as a Senior Reservoir Engineer in July 2013, she was employed as a principal reservoir engineer in Houston overseeing international projects and promoted to technical director for Latin America for two different companies for nine years. She was a Reservoir Engineering Advisor at Talos prior to becoming the Director of Reserves in April 2024. The Director of Reserves reports directly to our Vice President of Corporate Development. She is a member of the Society of Petroleum Engineers.

Drilling Activity

The table below notes the year in which the productive and dry wells are determined to be productive or not productive, as the case may be, as opposed to the year the well was drilled. The following table sets forth our drilling activity:

	Exploratory and Appraisal Wells						Development Wells						Total	
	Productive		Dry		Total		Productive		Dry		Total		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Consolidated Entities:														
Year Ended December 31, 2024														
United States	—	—	2.0	0.5	2.0	0.5	4.0	1.2	—	—	4.0	1.2	6.0	1.7
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
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

Present Activities

As of December 31, 2024, 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	0.3	1.0	0.5	1.0	0.5	1.0	0.1
Equity Method Investees:								
Mexico	—	—	—	—	4.0	0.4	—	—

Delivery Commitments

See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies* for additional information on firm transportation agreements in place with transportation pipelines for future transportation of oil production.

We have no firm sales commitments as of December 31, 2024.

Productive Wells

The number of our productive wells is as follows for the year ended December 31, 2024:

	Gross	Net
Consolidated Entities:		
Crude oil	268.0	199.9
Natural gas	78.0	33.9
Total(1)	346.0	233.8

(1) Includes 9.0 gross and 7.3 net wells with dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2024:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Consolidated Entities:						
United States:						
Deepwater	428,140	236,191	722,390	365,182	1,150,530	601,373
Shelf	280,449	195,777	54,935	37,724	335,384	233,501
Total United States	708,589	431,968	777,325	402,906	1,485,914	834,874
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, 2024 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
2025	79,286	30,623	—	—
2026	109,440	45,514	—	—
2027	106,560	48,329	—	—
2028	40,946	23,009	—	—
2029	49,759	32,482	—	—
2030 and beyond	391,334	222,949	3,261	572
Total	777,325	402,906	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,		
	2024	2023	2022
Consolidated Entities:			
Production Volumes:			
Crude oil (MBbls)	24,078	18,062	14,561
Natural gas (MMcf)	41,078	26,194	32,215
NGLs (MBbls)	2,969	1,767	1,793
Total (MBoe)	33,893	24,195	21,723
Percent of MBoe from crude oil	71 %	75 %	67 %
Average Sales Price (including commodity derivatives):			
Crude oil (per Bbl)	$ 75.07	$ 73.59	$ 68.40
Natural gas (per Mcf)	$ 2.65	$ 3.32	$ 5.30
NGLs (per Bbl)	$ 20.85	$ 18.18	$ 33.20
Average (per Boe)	$ 58.37	$ 59.86	$ 56.46
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 75.01	$ 75.17	$ 93.75
Natural gas (per Mcf)	$ 2.57	$ 2.60	$ 7.06
NGLs (per Bbl)	$ 20.85	$ 18.18	$ 33.20
Average (per Boe)	$ 58.23	$ 60.26	$ 76.05
Average Lease Operating Expense (per Boe)	$ 16.70	$ 16.10	$ 14.18

Crude Oil, Natural Gas and NGL Production, Prices and Production Costs — Significant Fields

Deepwater Area — Katmai Field

The following table sets forth certain information regarding our production volumes, average sales prices and average production costs for the Katmai Field, which consisted of 15% or more of our 2024 total estimated proved reserves on December 31, 2024:

	Year Ended December 31, 2024(1)
Production Volumes:	
Crude oil (MBbls)	2,254
Natural gas (MMcf)	4,898
NGLs (MBbls)	293
Total (MBoe)	3,363
Percent of MBoe from crude oil	67 %
Average Sales Price (excluding commodity derivatives):	
Crude oil (per Bbl)	$ 79.28
Natural gas (per Mcf)	$ 2.59
NGLs (per Bbl)	$ 29.89
Average (per Boe)	$ 59.52
Average Lease Operating Expense (per Boe)	$ 5.08

(1) The Katmai Field was acquired as part of the QuarterNorth Acquisition. The production volumes disclosed above are for the period March 4, 2024 to December 31, 2024.

Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 17 — *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 expected credit losses when necessary. For the year ended December 31, 2024, 48% and 17% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company and Exxon Mobil 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 America 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 natural 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 America, 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. 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). We may increase or decrease insurance coverage around our key assets, including potentially purchasing catastrophic bond instruments to the extent available to us.

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. Coverage is provided for damage to our assets resulting from a named U.S. Gulf of America 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 $30.0 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 America Deepwater drilling wells, $150.0 million for U.S. Gulf of America Shelf drilling wells, $75.0 million for U.S. Gulf of America 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 becoming 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.

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 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 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 America 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 America 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 pursuant to various federal laws, including the federal Outer Continental Shelf Lands Act ("OCSLA"). For offshore operations, lessees are required to 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 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. However, the Trump Administration has taken action to revoke or rescind certain actions by the previous administration that placed limitations on offshore oil and gas leasing and permitting. For example, President Trump issued Executive Orders lifting restrictions on oil and gas leasing off the coast of Alaska and encouraging further OCS oil and gas exploration and production. The impact of these and any similar future actions taken by the Trump Administration are uncertain at this time.

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. We were awarded leases on all thirteen of our high-bid blocks. The 2024-2029 Five-Year Leasing Program began on July 1, 2024, and will continue through June 30, 2029, and includes a maximum of three potential oil and gas lease sales in the U.S. Gulf of America scheduled to be held in years 2025, 2027 and 2029. It is possible, however, that this program could be delayed by opposing lawsuits that were filed on February 12, 2024 by the American Petroleum Institute and Earthjustice representing multiple environmental groups, both of which are challenging BOEM's actions. Despite these challenges, on April 1, 2024, BOEM announced the availability of the Area Identification for proposed U.S. Gulf of America lease sales 262, 263 and 264 pursuant to the 2024-2029 Five-Year Leasing Program. On December 13, 2024, BOEM published its Draft Programmatic Environmental Impact Statement for proposed U.S. Gulf of America lease sales 262, 263 and 264. The Trump Administration may seek to take additional action to revise the Five-Year Leasing Program, although the substance and timing of such action cannot be predicted. 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 delays related to the National Environmental Policy Act 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 adopted 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 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. Although it is not certain what actions the Trump Administration may take with respect to these standards, if any, 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 leases 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 America can have a significant impact on oil and natural gas operations and can result in temporarily or permanently 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.

BOEM Financial Assurance Requirements — BOEM has generally required that lessees demonstrate financial strength and reliability under its regulatory standards, and provide acceptable financial assurances, such as surety bonds, to assure satisfaction of lease obligations, including decommissioning activities on the OCS. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain sufficient bonds or other surety in all cases.

While there has been substantial uncertainty with respect to BOEM's financial assurance requirements in recent years, on April 15, 2024, BOEM issued a final rule entitled "Risk Management and Financial Assurance for OCS Lease and Grant Obligations," which significantly increases the amount of new supplemental financial assurance required from certain lessees and grant holders conducting operations on the OCS. The final rule replaced BOEM's prior five-point test previously used to determine whether an OCS lessee or grant holder was required to obtain supplemental financial assurance. The 2024 final rule instead requires lessees to meet one of two criteria based on: (1) the credit rating of the lessee or (2) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. As a result, BOEM no longer considers or relies upon the financial strength of predecessors in title in determining whether, or how much, supplemental financial assurance will be required by current lessees and grant holders. The final rule, which became effective on June 29, 2024, adopts a three-year phased compliance period for fully meeting BOEM's supplemental financial assurance demand. Per BOEM's June 28, 2024 news release, BOEM indicated it may take up to 24 months from that date to complete the processing of financial assurance demands for execution. On June 17, 2024, prior to the effective date of the final rule, BOEM's rule was challenged in the U.S. District Court for the Western District of Louisiana by multiple oil and gas industry groups and the States of Mississippi, Louisiana, and Texas. The implementation of the final rule is not currently stayed, and the outcome of these challenges remains uncertain. However, the Trump Administration may seek to suspend, revise or rescind this final rule pursuant to Interior Secretary Burgum's Secretarial Order 3418 dated February 3, 2025. The substance and timing of such legal and regulatory actions cannot be predicted at this time.

The future cost of compliance with respect to supplemental financial assurances, including the obligations imposed on us, whether as current or predecessor lessee or grant holder in respect of BOEM's final rule or any new, more stringent, rules related to supplemental financial assurances could materially and adversely affect our financial condition, cash flows, liquidity and results of operations. Additionally, regardless of the final rule, 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 have undergone significant reformation over the past decade, and the legal framework continues to evolve as SENER, the CNH, the Federal Electricity Commission ("CFE") and other Mexican regulatory bodies issue new regulations and guidance.

In August 2023, the CNH issued the "Guidelines on Abandonment, Relinquishment, and Restitution" which regulate the mechanisms for coordination between CNH, SENER, and ASEA (the Agency for Safety, Energy, and Environment governing hydrocarbon activities) to effectively regulate and oversee abandonment and relinquishment activities. The Guidelines require the establishment of financial mechanisms for abandonment and imposes obligations and procedures to be followed for the proper abandonment of wells. Furthermore, they set forth the procedures and requirements for obtaining the necessary authorization for the disposal and removal of materials related to hydrocarbon exploration and extraction operations.

In September 2024, SENER published a new Order relating to hydrocarbon export permits (the "Order"). The Order provides SENER with more discretion on issuing long-term export permits and provides that such permits shall only be issued if the need for their granting is based on the "social and economic importance for the Mexican State" in accordance with the National Development Plan, in addition of having an infrastructure project associated therewith.

In October 2024, the President of Mexico signed a constitutional reform to transform the energy sector in Mexico by, amongst other things, changing the legal status of the CFE and PEMEX, the state-owned oil company, to "public companies of the state." This is intended to allow the state to exercise greater control over the energy industry and, in turn, limit private sector participation. Subsequent legislation, which was sent to the Congress of the Union in January 2025, dissolves the Mexican Energy Regulatory Commission (the "CRE") and the CNH, and assigns the functions of those entities, such as permits for electricity generation, establishment of tariffs and pricing, to a newly created National Energy Commission ("NEC"), an independent body under SENER. The ultimate impact of this energy reform and any future regulatory changes made pursuant to the reform is uncertain at this time. Further, the regulations governing the energy industry are subject to change, and it is possible that SENER, the NEC or other Mexican regulatory bodies may impose new or revised requirements that could increase our equity method investment's operating costs and/or capital expenditures for operations in Mexican offshore shallow waters.

Our Mexico operations are subject to regulations issued by the ASEA. This includes 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. In December 2024, the ASEA published the General Administrative Provisions Establishing the Guidelines Applicable to the Construction and Maintenance of Wells for Hydrocarbon Exploration and Extraction (the "Construction and Maintenance Guidelines"), which replace existing regulations related to conducting well development activities. The Construction and Maintenance Guidelines, effective March 2025, impose requirements related to, among other things, risk analysis and management reporting, implementation of safety systems and preventative measures, technical construction requirements, well maintenance equipment, well completion, and well plugging.

In February 2025, the Executive Branch presented a bill containing a draft decree for the issuance of a new Hydrocarbons Sector Law (the "LSH") to the Senate. If approved, the LSH will replace the Hydrocarbon Law, which has been in force since August 2014. As a consequence, the CNH declared the suspension of deadlines and terms for the reception, processing, and resolution of acts, filings and procedures handled by the CNH. Similarly, the CNH tolled the time periods applicable to exploration periods, appraisal period, and transition programs under exploration and extraction contracts. These actions could adversely impact our operating costs and capital expenditures for our operations in Mexican offshore shallow waters.

Environmental and Occupational Safety and Health Regulations

We are subject to various federal, state, local and foreign laws and regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental and occupational safety and health 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). In recent years, both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. 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. 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 future administrations 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 to BOEM 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 could 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 the first Trump 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, in April 2022, the Biden Administration CEQ issued a final rule considered as "Phase I" of a two-phased approach to modifying the NEPA. Then, in May 2024, the CEQ finalized "Phase 2," the "Bipartisan Permitting Reform Implementation Rule," which revised the implementing regulations of the procedural provisions of NEPA and implemented the amendments to NEPA included in the June 3, 2023, Fiscal Responsibility Act of 2023. The final rule was challenged by various states. Most recently, in November 2024, the U.S. Court of Appeals for the D.C. Circuit held that the CEQ lacks authority to issue NEPA regulations. As a result of this ruling and the new Trump Administration, there is significant uncertainty with respect to current and future NEPA regulations. For example, on January 20, 2025, President Trump issued an Executive Order directing the CEQ to issue new guidance and propose rescinding the existing NEPA regulations to "expedite and simplify the permitting process." The NEPA process, however, 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 the first Trump Administration 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 April 12, 2024, the FWS issued a final rule that revised the requirements for an incidental take permit application. The Marine Mammal Protection Act, as amended ("MMPA"), similarly prohibits the taking of marine mammals without authorization. We cannot predict what actions the Trump Administration may take with respect to these regulations, if any, or the timing with respect to the same. 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. Further, on July 24, 2023, NMFS proposed to designate approximately 28,300 square miles of the Gulf of America as critical habitat for the Rice's whale, although this critical habitat has not yet been finalized. In addition, on July 19, 2023, the NMFS proposed a critical habitat for the Green sea turtle, which encompasses the majority of the U.S. Gulf of America, although this critical habitat has not yet been finalized either. These actions and others may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas. For example, on August 17, 2023, BOEM issued a NTL that provided recommendations and guidance regarding avoidance and mitigation measures for vessel transit within the expanded Rice's whale area as designated in the proposed critical habitat designation for the Rice's whale. On February 20, 2025, BOEM rescinded this NTL in response to an order by the DOI Secretary issued on February 3, 2025. The designation of new endangered species or a critical habitat for protection under the ESA, MBTA, and MMPA resulting in operating restrictions or a ban in affected areas could adversely affect our business and results of operations and increase our operating costs.

Additionally, projects subject to agency review under the ESA can be subject to delay due to third-party challenges of the sufficiency of the ESA review. For example, on August 19, 2024, a U.S. District Court in Maryland ruled in favor of a coalition of environmental groups that filed suit against NMFS in 2020, claiming that NMFS's 2020 Biological Opinion, together with the associated reasonable and prudent alternative and incidental take statement, which covers all activities associated with the OCS oil and gas program in the Gulf of America, did not comply with the ESA or the Administrative Procedure Act, and vacated the 2020 Biological Opinion effective December 20, 2024. NMFS filed a motion to alter or amend the court's ruling requiring vacatur of the 2020 Biological Opinion by December 20, 2024, stating that it was unable to issue a new biological opinion by that date. On October 21, 2024, the court extended the vacatur deadline to May 21, 2025, which NMFS believes provides sufficient time to prepare and issue a new biological opinion. Industry groups appealed the Maryland District Court's decision to the U.S. Court of Appeals for the Fourth Circuit. The outcome of that challenge remains uncertain. Although NMFS expects to submit a new biological opinion in advance of the May 2025 deadline, any revised biological opinion that NMFS issues may impose additional operational restrictions and may face additional scrutiny and legal challenges. Without an active OCS Gulf of America oil and gas program biological opinion in place, all permits, plans and government actions would likely require individual project-specific ESA consultations between BOEM or BSEE (as applicable) and NMFS, which could cause significant delays and adversely impact our ability to obtain plans, permits and government approvals required for our Gulf of America operations until a new biological opinion is issued by NMFS.

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 regulate these wastes as non-hazardous 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 waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste. Moreover, facilities where we generate hazardous waste are subject to EPA inspection, and any noncompliance discovered or otherwise alleged by EPA can result in the imposition of substantial fines and penalties.

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. Since then, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local, and tribal air agencies for implementing these 2015 standards for ground-level ozone. In December 2020, the EPA published its decision to retain the 2015 NAAQS for ground-level ozone. However, several groups have filed litigation over this December 2020 decision, and on August 21, 2023, the EPA announced a new review of the ozone NAAQS to reflect updated ozone science in combination with the reconsideration of the December 2020 decision. However, the review remains ongoing and is not expected to be complete before the EPA's five-year cycle for NAAQS review in December 2025. It also remains unclear what actions, if any, the Trump Administration may take with respect to the review. 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. 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.

In recent years there has been increased regulation of methane emissions from the oil and gas sector. For example, in December 2023, the EPA published a final rule establishing more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Fines and penalties for violations of these rules can be substantial. The final methane rule is currently being challenged by 23 states and a coalition of industry groups in the U.S. Circuit Court of Appeals for the D.C. Circuit. In February 2025, the court granted the EPA's motion to hold the consolidated cases in abeyance while the EPA reviews the final rule. While the Trump Administration may take action to revise, repeal, or otherwise modify the final methane rule, the substance or timing of such action, if any, is uncertain. Although these federal methane rules only apply to onshore and state water oil and gas operations, more stringent regulation of methane or greenhouse gases from the oil and gas sector has the potential to increase our compliance costs and could adversely impact 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. However, on January 20, 2025, President Trump issued an Executive Order re-withdrawing the United States from the Paris Agreement and from any other commitments made under the United Nations Framework Convention on Climate Change. Additionally, President Trump revoked any purported financial commitment made by the United States pursuant to the same. The full impact of these actions is uncertain at this time.

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 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, though many of these initiatives have been subsequently revoked by President Trump. See Part I, Items 1 and 2. Business and Properties — Government Regulation — Outer Continental Shelf ("OCS") Regulation for more information. Other actions that were pursued by the Biden Administration, and may be pursued in future administrations, 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, the Biden Administration previously issued a pause on approvals for LNG export facilities, which was subsequently struck down in federal court. Following the legal challenges, the Biden Administration released a study on the economic and environmental impacts of LNG exports, finding, based on a range of scenarios that vary in assumptions about global climate policies and technology availability, that increased U.S. LNG exports are associated with higher global GHG emissions. While President Trump has issued an executive order directing the Department of Energy to restart reviews of LNG export applications, we cannot predict what impact the study released by the prior administration may ultimately have. Additionally, the IRA 2022 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. However, on January 20, 2025, President Trump issued an Executive Order directing agencies to immediately pause the disbursement of certain funds appropriated through the IRA 2022. This was shortly followed by the Office of Management and Budget rescinding the freezing of federal grants and loans, although not its effort to review the processes with respect to federal spending. The impact of this Executive Order, the Office of Management and Budget's actions, and any similar future actions to limit the incentives offered under the IRA 2022 is uncertain at this time. 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. Certain 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 and some of them may elect not to provide funding for fossil fuel energy companies, although this trend has waned recently, with several high-profile banks and institutional investors withdrawing from various associations that aim to limit the financing of such industries. 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. While we cannot predict how or to what extent sustainable lending and investment practices may impact our operations, 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 finalized a rule in March 2024 that establishes a framework for the reporting of climate risks, targets and metrics. The rule is currently stayed pending litigation and on February 11, 2025, SEC Acting Chairman Mark T. Uyeda requested that the U.S. Court of Appeals for the Eighth Circuit not schedule argument in the case while the SEC reconsiders the March 2024 rule. 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, 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.

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 $1,584,648 per violation, per day for 2025 (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 700 employees as of December 31, 2024. 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.

We also maintain a Human Rights Policy which embodies basic human rights tenets that we expect all of our employees, as well as our vendors, partners and suppliers, to follow.

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/governance-documents 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 and benefit programs related to all employees.

The Nominating & Governance Committee of our Board (the "NGC") reviews succession planning for the Chief Executive Officer ("CEO") position, monitors and reviews the development and progression of potential successors and consults with the CEO 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 head of Human Resources, together with our executive leadership team, is responsible for our workforce management policies and programs, reporting directly to the CEO, and providing regular updates to the Compensation and SSCR Committees on human capital matters. The CEO and other executive officers are accessible to all employees through town hall meetings where the executive team discusses corporate matters and other topics pertinent to employees, answers questions and receives employee feedback.

Workforce Composition — As of December 31, 2024, we employed approximately 700 employees located primarily in Texas, Louisiana and Mexico. Approximately 380 (54%) of these employees are in our offshore operations and seven (7) employees are Mexican nationals working in Mexico. In addition, we utilize third-party contract companies to provide consultants to perform various offshore and corporate services on an as needed basis. None of our employees are represented by labor unions or covered by any collective bargaining agreement.

Safety — Safety is a core value and the number one priority in the operation of our business. Our focus on safety starts at the top with our Board, our CEO, and our Executive Head of Operations, who is directly responsible for all safety initiatives, and our head 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 ("SEMS") includes a stringent "Stop Work Authority" program 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 the most recent 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. Approximately 280 employees have participated in this leadership training. We also reimburse the costs of 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 various financial, operational, safety, environmental 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 most recent Definitive Proxy Statement on Form DEF 14A, filed with the SEC on April 17, 2024 for further 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 offer a mental health plan to support employees and their families' mental well-being. In 2023, we contracted with a third-party healthcare company to establish 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

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 are 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 semi-annual redeterminations based on pricing models to be determined by the lenders at such time. In addition, there is currently an availability cap such that, if the aggregate exposure of all lenders under the Bank Credit Facility equals or exceeds a certain amount (which is below the borrowing base) at any time, the approval of lenders holding at least two-thirds of the aggregate commitments is required to make any additional loans or issuance of any additional letters of credit. Further, if we are unable to replace proved reserves either through acquisitions or new drilling activity, our borrowing base and available liquidity under our Bank Credit Facility will be reduced. In addition, 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, borrowing base under our Bank Credit Facility, 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, 2022 through December 31, 2024, the daily NYMEX WTI crude oil price per Bbl ranged from a low of $66.61 to a high of $123.64, and the daily NYMEX Henry Hub natural gas price per MMBtu ranged from a low of $1.21 to a high of $13.20.

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, tariffs, 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, Mexico, Canada and Africa;

- armed conflicts and hostilities such as Russia's ongoing war in Ukraine and 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 in connection with the U.S. and Mexican presidential transitions;
- changes in tariffs, trade barriers, price and exchange controls and other regulatory requirements;
- 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 74%, 19%, and 7%, respectively, of our estimated proved reserves as of December 31, 2024, and approximately 71%, 20%, and 9%, respectively, of our 2024 production on a Boe 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 America 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.

The threat from these risks may be currently potentially heightened due to the geopolitical tension between Mexico, Canada and the U.S. 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 America 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 future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable in order to replace or grow our proved reserves. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves during the initial few years of production. Substantially all of our operations are in the U.S. Gulf of America where proved reserves generally have shorter reserve lives than proved reserves in many other producing regions of the United States. 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. Furthermore, 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.

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.

Mexico's most recent presidential election was held in July 2024. Presidential reelection is not permitted in Mexico. President Claudia Sheinbaum took office on December 1, 2024 and at this time we cannot predict the extent of changes that will result from this change in administration. Similarly, Canadian Prime Minister Justin Trudeau announced in January 2025 that he intends to resign by March 24, 2025, and Canada will hold federal elections in 2025. Political events in Mexico and Canada, including in conjunction with the Trump Administration's proposed tariffs and the corresponding geopolitical tensions between Mexico and the U.S. as well as between Canada and the U.S., 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. We expect the ongoing war to prolong disruptions in the region.

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 cannot 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 globally in a manner that would reduce the revenues we receive for our oil and gas production.

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 although in January 2025 Israel and Hamas entered into a ceasefire agreement, the duration and success of such agreement remains uncertain at this time. Hostilities between Israel and Hamas have 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.

Recent and pending management changes could disrupt our operations and impair our ability to attract and retain key personnel.

We have experienced recent changes to our senior management team, including the departure of our former President and Chief Executive Officer on August 29, 2024 and our former Interim President and Chief Executive Officer effective January 6, 2025. On February 3, 2025, we announced the appointment of Paul R. Goodfellow to serve as our President and Chief Executive Officer, and as a member of our Board of Directors, effective March 1, 2025. Changes in our senior management may disrupt our operations, impact customer and partner relationships, and impair our ability to recruit and retain other needed personnel. Any such disruption or impairment could have an adverse effect on our business.

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 2024 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, 2024 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, 2024, approximately 23% of our estimated proved reserves (by volume) were undeveloped and approximately 21% 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, 2024, approximately 48% 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 or closure of this infrastructure could result in the shut-in of producing wells or delays or discontinuance of development plans for our properties. Disruptions to gathering systems, pipelines, and processing facilities - whether due to maintenance, weather, abandonment, closures, or otherwise could negatively impact our ability to continue production and 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 slightly declining during 2023 and 2024. 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 have periodically increased interest rates in an effort to curb inflationary pressure on the costs of goods and services across the U.S. and globally. While the Fed began to reduce benchmark interest rates during 2024, the continuation of elevated rates could have the effect of raising the cost of capital and depressing economic growth, either of which—or the combination thereof—could negatively impact 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 provide the financial assurances in sufficient amounts or on reasonably acceptable terms to comply with regulatory requirements, or otherwise, in order to conduct our business in the OCS.

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

On April 15, 2024, BOEM issued a final rule, entitled “Risk Management and Financial Assurance for OCS Lease and Grant Obligations,” which significantly increases the amount of new supplemental financial assurance required from lessees and grant holders conducting operations on the OCS. The final rule replaced BOEM’s prior five-point test previously used to determine whether an OCS lessee or grant holder was required to obtain supplemental financial assurance. The 2024 final rule instead requires lessees to meet one of two criteria based on: (1) the credit rating of the lessee or (2) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. As a result, BOEM no longer considers or relies upon the financial strength of predecessors in title in determining whether, or how much, supplemental financial assurance will be required by current lessees and grant holders. The final rule, which became effective on June 29, 2024, adopts a three-year phased compliance period for fully meeting BOEM’s supplemental financial assurance demand. Per BOEM’s June 28, 2024 news release, BOEM indicated it may take up to 24 months from that date to complete the processing of financial assurance demands for execution. Prior to the effective date of the final rule, BOEM’s rule was challenged in the U.S. District Court for the Western District of Louisiana by multiple oil and gas industry groups and the States of Mississippi, Louisiana, and Texas on June 17, 2024. The implementation of the rule is not currently stayed, and the outcome of these challenges, as well as regulatory changes that may be implemented by the Trump Administration, remains uncertain.

BOEM 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 are unable to comply with the BOEM requirements to provide additional surety bonds or other financial assurances in the amounts and under the time periods required by BOEM, BOEM could take actions that would materially adversely impact our operations and our properties, including commencing enforcement proceedings or take other remedial action, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel federal leases associated with our noncompliance, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. Additionally, regardless of the 2024 final rule, 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.

Moreover, under our existing and future indemnity agreements, surety companies have the right to demand additional collateral, such as cash or letters of credit, to support existing bonds or to obtain future bonds. We cannot provide assurance that we will be able to satisfy collateral demands. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position would be significantly 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.

Further, as a result of adverse developments in restructurings and bankruptcies of companies operating in the OCS, a number of surety companies have left the offshore surety market, which has materially reduced the availability of surety bonds for projects in the OCS and may reduce the ability of companies operating in the OCS to obtain bonding without posting collateral. As a result, bonds may not be available to us on commercially reasonable terms, including requiring collateral, which may lead to significantly increased costs on our operations. Further, there may not be sufficient surety bond capacity available for companies in the OCS which could consequently have a material adverse effect on our ability to conduct our operations.

All of these factors may make it more difficult for us to obtain the financial assurances necessary to conduct operations on the OCS. We cannot predict (i) what actions the Trump Administration may take with respect to these regulations and the timing with respect to the same or (ii) the availability to us of surety bonds on commercially reasonable terms in the marketplace. As a result, there is significant uncertainty with respect to the financial assurance regulatory requirements and current market availability of surety bonds. These factors could, in the future, result in significantly increased costs on our operations, reduced cash flows and our liquidity 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 and Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Known Trends and Uncertainties — Financial Assurance Requirements and — Financial Assurance Market Outlook.

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

As an oil and gas producer, we face 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 U.S. government has issued warnings that U.S. energy assets may be at greater risk of future attacks than other targets in the U.S. We depend on the uninterrupted operation of our technology in many areas of our business and operations, including, but not limited to, monitoring our platforms and pipelines, processing and recording financial and operating data, oversight and analysis of our operations and communicating with our employees, customers, and service providers. We also collect and store sensitive data in the ordinary course of our business, including personally identifiable information as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. Additionally, we rely on third-party vendors and service providers, including suppliers, cloud-based storage providers, and industrial equipment manufacturers, which may present additional cybersecurity risks beyond our direct control. If a third-party provider failed to adequately safeguard our data or their systems, or if they experienced a security breach, it could compromise our systems, disrupt our operations, or result in the unauthorized disclosure of sensitive information.

We and our service providers have, from time to time, been subject to cybersecurity attacks and security incidents. Cybersecurity attacks in particular are increasing globally in frequency and in sophistication and include, but are not limited to, malicious software, surveillance, credential stuffing, spear phishing, social engineering, use of deepfakes (i.e., highly realistic synthetic media generated by artificial intelligence) 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. Although we have implemented and maintain commercially reasonable security measures, including detection and prevention systems, regular cybersecurity assessments, employee training programs, and an incident response plan, these measures may not be effective in preventing security threats, detecting them promptly, or minimizing their impact. The techniques used by attackers continue to evolve, making it difficult to anticipate, identify, or prevent future attacks. Some attacks may go undetected for extended periods or may not be recognized until they have already caused harm. Attackers increasingly employ sophisticated methods to bypass security controls, evade detection, and obscure forensic evidence, which can hinder our ability to investigate and respond effectively.

A successful cyberattack or security breach could compromise our networks, resulting in unauthorized access, exposure, loss, or theft of sensitive information. Such incidents may lead to legal claims, litigation, regulatory scrutiny, enforcement actions, financial penalties, and fines. We may also incur significant costs related to system restoration, compliance measures, operational disruptions, reputational damage, and diminished customer confidence in our products and services. Any of these outcomes could have a material adverse impact on our business and financial performance. Prolonged outages or disruptions in our information technology infrastructure could impair our ability to deliver services, meet customer expectations, or comply with regulatory requirements. As cybersecurity and data privacy threats continue to evolve, we may need to commit substantial resources to strengthen our security framework, ensure regulatory compliance, and address potential vulnerabilities. The expenses associated with these efforts, including investigating and remediating security incidents, could be significant. Although we maintain cyber insurance to help mitigate financial risks associated with cyber incidents, these policies have inherent limitations and may not cover all potential losses, including reputational damage or regulatory penalties. As a result, our insurance coverage may not fully protect against all cybersecurity-related risks. Additionally, as cyberattacks become more frequent and severe worldwide, the availability and affordability of comprehensive coverage may continue to decline. To date, we have not experienced any material losses relating to cyberattacks. However, there can be no assurance that we will not suffer such losses in the future. No security measure is infallible. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

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

We may not serve as operator of all our planned wells. For example, in March 2022, the final Unitization Resolution 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. In such circumstances where we are not operator, we will have limited ability to exercise influence over the operations and associated costs. Our dependence on the operator and other working interest owners, and the limited ability to influence operations and associated costs, could prevent us from realizing the anticipated results of drilling or acquisition activities.

The success and timing of development and exploitation activities on properties operated by others further 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, financial resources, qualified operating personnel and technology decisions;
- approval of other participants in drilling wells;
- the operator’s ability to obtain permits and regulatory approvals;
- risk of other non-operator’s failure to pay their share of costs, which may require us to pay our proportionate share of the defaulting party’s share of costs; and
- the timing and cost of P&A operations.

In addition, we have limited influence and control over operational decisions and 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 anticipate;
- 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.

For example, PEMEX is the operator of our Zama Field project in offshore Mexico. As a result, we have limited ability to influence the operational or technical decisions made, including those that affect the timing and costs of the development of that project. 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 has, in recent years, been a heightened area of focus and regulatory and disclosure requirements in the United States. For example, in March 2024, the SEC finalized a rule that requires 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 Scope 1 and Scope 2 emissions. The rule is currently stayed pending litigation and the SEC under the Trump Administration is expected to repeal the rule; however, the timeline for any repeal, if at all, is subject to a number of uncertainties. For additional information about government regulation related to environmental and worker safety matters, please see Part I, Items 1 and 2. Business and Properties — 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.

Our ability to obtain permits and governmental approvals for our U.S. Gulf of America operations may be delayed by the court-mandated vacatur of the National Marine Fisheries Services' Gulf of America Biological Opinion if NMFS is unable to publish a revised biological opinion by the vacatur date.

The Endangered Species Act, as amended, restricts activities that may affect federally identified endangered and threatened species or their habitats. On August 19, 2024, a U.S. District Court in Maryland ruled in favor of a coalition of environmental groups that had challenged NMFS's 2020 Biological Opinion which covers all activities associated with the OCS oil and gas program in the Gulf of America, and vacated the 2020 Biological Opinion as of December 20, 2024. On September 16, 2024, NMFS filed a motion to alter or amend the court's ruling requiring vacatur of the 2020 Biological Opinion by December 20, 2024, stating that it was unable to issue a new Biological Opinion by that date. On October 21, 2024, the court extended the vacatur deadline to May 21, 2025. Industry groups appealed the Maryland District Court's decision to the U.S. Court of Appeals for the Fourth Circuit. The outcome of that challenge remains uncertain at this time. Although NMFS expects to submit a new biological opinion in advance of the May 2025 deadline, any revised biological opinion may impose additional operational restrictions and may face additional scrutiny and legal challenges which could further delay or impact our operations. Without an active biological opinion in place, all permits, plans and government actions in the U.S. Gulf of America would likely require individual project-specific consultations under the Endangered Species Act between BOEM or BSEE (as applicable) and NMFS, which could cause significant delays and adversely impact our ability to obtain plans, permits and government approvals required for our Gulf of America operations in a timely manner. For further information please see Part I, Items 1 and 2. Business and Properties — Environmental and Occupational Safety and Health Regulations——Endangered Species Act.

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.

Stricter environmental, health and safety standards applicable to our operations and those of the oil and gas industry more generally have been implemented during the past few years. For example, President Biden issued the "Executive Order on Tackling the Climate Crisis at Home and Abroad" on January 27, 2021 (the "Climate Change Executive Order"), which directed the Secretary of the Interior to halt 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. President Trump signed several Executive Orders rescinding many of the Biden Administration's climate-related initiatives, including revoking the Climate Change Executive Order. However, the ultimate impact of future actions taken by the Trump Administration related to offshore leasing is uncertain at this time.

Gulf of America lease sales are conducted pursuant to Five-Year Leasing Programs under the Outer Continental Shelf Lands Act. The most recent Five-Year Leasing Program began on July 1, 2024, and will continue through June 30, 2029. It is possible, however, that this 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. Despite these challenges, on April 1, 2024, BOEM announced the availability of the Area Identification for proposed Gulf of America lease sales 262, 263 and 264 pursuant to the 2024-2029 Five-Year Leasing Program. On December 13, 2024, BOEM published its Draft Programmatic Environmental Impact Statement for proposed U.S. Gulf of America lease sales 262, 263 and 264. Lease Sale 262 is tentatively scheduled for 2025. The Trump Administration, however, may seek to take additional action to revise the Five-Year Leasing Program, though the substance and timing of such action cannot be predicted. Any future actions 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 and Biden Administrations, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. For example, 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 well's maximum kick tolerance design limits and includes more stringent requirements for failure reporting. The Trump Administration has expressed its intent to reduce regulatory burdens related to permitting of fossil fuel projects, though we cannot predict what actions the administration may take with respect to these regulations, if any, and the timing with respect to the same. 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.

Regulatory actions or any new laws, executive orders, regulations, judicial proceedings or other legal or enforcement initiatives, that impose increased restrictions, costs or more stringent operational standards could delay or disrupt our ability to obtain permits and governmental approvals, delay or restrict 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, legal proceedings 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. In addition, we may be forced to permanently discontinue development plans or production. 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, winter storms and hurricanes in the U.S. Gulf of America 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 and along the U.S. Gulf of America. 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, winter storms and other adverse weather conditions in the U.S. Gulf of America. In addition, the unavailability of infrastructure may impact our ability to continue production. 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 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 America 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. For example, as a result of ongoing litigation between the U.S. Coast Guard and several insurance providers, a number of insurers providing insurance related to the OPA regulations have left the insurance market, which has materially reduced the availability of OPA insurance. While we currently meet the qualifications to self-insure our OPA financial responsibility, if we are unable in future years to fully self-insure our required OPA coverage, we may not be able to obtain adequate OPA insurance required to comply with OPA. 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. Further, 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 America, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could materially and adversely affect our financial condition, cash flows, business properties, liquidity 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.

We conduct exploration, development and production operations primarily on the deep Shelf and in the Deepwater of the Gulf of America, which present numerous risks.

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. Moreover, drilling wells in the U.S. Gulf of America Deepwater and/or in the Gulf Coast deep Shelf require increased capital costs due to various conditions such as geological complexity, additional depths, high temperatures and pressure and adverse weather in the areas in which we have oil and natural gas. 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 pursue additional operational activity in the future and acquire additional fields and leases in the Deepwaters of the U.S. Gulf of America. Exploration for oil or natural gas in the Deepwaters of the U.S. Gulf of America generally involves greater operational and financial risks than exploration in the shallower waters of the U.S. Gulf of America 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 America 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, such as Shell Trading (US) Company and Exxon Mobil 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 America 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 entered into certain agreements which contain minimum volume commitments. Any failure by us to satisfy these commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.

From time to time, we have entered into, and may in the future enter into, agreements or similar commercial arrangements, some of which expose the Company to significant economic loss, such as transportation contracts with minimum volume commitments that we may be unable to satisfy due to reductions in our drilling activity resulting in insufficient production. As of December 31, 2024, our total future minimum transportation fees totaled approximately $36.9 million through 2030. If we have insufficient production to meet the minimum volume commitments under any of these agreements, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operations and financial position. Further information about these commitments can be found under Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies*.

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. Further, the Organisation for Economic Co-Operation and Development, an international association of 38 countries that includes the United States, has adopted a set of international tax model rules known as the "Pillar Two" framework, a central component of which is the imposition of a global minimum corporate tax rate of 15% to multinational enterprises that have consolidated group revenues above a specified threshold. While we are still assessing the potential impacts of the Pillar Two rules to our business and our subsidiaries, any incremental taxes attributable to Pillar Two could be significant and could adversely impact our after-tax profitability. Such proposed legislative changes, the ratification of the Multilateral Instrument in the jurisdictions in which we operate and any incremental taxes attributable to Pillar Two could result in further changes to our global taxation. Future tax legislative or regulatory changes in the United States, Mexico or in any other jurisdictions in which we operate or have subsidiaries now or in the future could also adversely impact our after-tax profitability.

Our future tax liabilities may be greater than expected if our net operating loss ("NOL") and interest expense carryforwards are limited.

As of December 31, 2024, we had approximately $108.7 million of tax-affected U.S. federal NOL carryforwards and $12.4 million of tax-affected state NOL carryforwards. Some of the U.S. federal NOL carryforwards expire in 2036 while others have no expiration date. The state NOL carryforwards have no expiration date. As of December 31, 2024, we also had approximately $75.0 million of tax-affected U.S. federal and state interest expense carryforwards. Utilization of these NOL and interest expense carryforwards depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), generally imposes an annual limitation on the amount of NOL and interest expense carryforwards that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382 of the Code). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of such corporation's stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. All of our U.S. federal NOL carryforwards and certain of our interest expense carryforwards are currently subject to limitation under Section 382 of the Code. In the event that we were to undergo an ownership change in the future, utilization of our NOL and interest expense carryforwards would be subject to limitation under Section 382 of the Code. Any unused annual limitation generally may be carried over to later years until they expire. Limitations similar to those applicable under Section 382 of the Code apply for U.S. state income tax purposes. Any limitation on our ability to utilize our NOL and interest expense carryforwards against income or gain we generate in the future could increase our future tax liabilities and adversely affect our operating results and cash flows.

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. In addition, our operations in Mexico are subject to regulations promulgated by ASEA, governing the protection of health, safety and the environment. Permit holders under ASEA must comply with requirements relating to insurance, facility construction and design, law compliance, and risk analysis scenarios. See Part I, Items 1 and 2. Business and Properties — Government Regulation for additional disclosure relating to the legal requirements imposed by SENER, CNH, ASEA or other Mexican regulatory bodies to which we may be subject in the pursuit of our operations conducted through our equity method investment.

Additionally, we are a signatory to the Block 7 PSC, making us 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. 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 are subject to the U.S. Foreign Corrupt Practices Act and may be exposed to liabilities thereunder.

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, to which a subsidiary of Talos Mexico is a party, violations of the FCPA, by any signatory to the PSC, 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 offshore and onshore petroleum and natural gas production categories. However, on January 20, 2025, President Trump issued an Executive Order which paused distribution of federal funds appropriated through the IRA 2022. The pause was aimed at providing time to review the processes, policies and issuance of various grants, loans, contracts or financial disbursements of appropriated funds. However, on January 29, 2025, the Office of Management and Budget rescinded the freezing of federal grants and loans, although not its efforts to review the processes with respect to federal spending. At this time, the potential impact of these various actions remains uncertain. The IRA 2022 also imposes a methane emissions charge on waste emissions of methane from certain oil and gas facilities. In November 2024, the EPA issued a final rule to implement the waste emissions charge. Pursuant to the IRA 2022 and the EPA's implementing regulation, the charge, which applies to reported emissions that exceed statutorily specified waste emissions thresholds set by Congress, was set at $900 per ton of methane in 2024, and increasing to $1,200 in 2025, and $1,500 in 2026 and each year after. The Congress and the Trump Administration may take action to amend, rescind or otherwise modify the IRA 2022 and the implementing regulations, respectively, though the impact or timing of such action cannot be predicted. However, such additional fees could impact our operating costs. These policy, legislative and 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 at the federal, state or local level, 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.

Any increased attention to environmental, social and governance matters may impact our business.

In recent years, there has been increasing attention to climate change and societal expectations on companies to address climate change and substitute energy sources for fossil fuels, which 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 or hypothetical scenarios that may or may not be representative of actual or forecasted risks or events, including the costs associated therewith. Such assumptions and calculations or hypothetical scenarios are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established 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 Environmental and Sustainability 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. While such ratings do not impact all investors' investment or 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-related 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, the SEC has recently taken enforcement action against companies for ESG-related misconduct, including alleged greenwashing. Certain regulators, such as the SEC and various state agencies, as well as non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG-related statements, emission reduction claims, approaches to accounting for GHG emissions reductions, or other ESG-related goals or standards were misleading, false, or otherwise deceptive. Certain employment practices and inclusion initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. More recent political developments could mean that the Company faces increasing criticism or litigation risks from certain "anti-ESG" parties, including various governmental agencies. Such sentiment may focus on the Company's environmental commitments (such as reducing GHG emissions) or its pursuit of certain employment practices or social initiatives that are alleged to be political or polarizing in nature or are alleged to violate laws based, in part, on changing priorities of, or interpretations by, federal agencies or state governments. The complex regulatory and legal frameworks applicable to such initiatives continue to evolve. Consideration of ESG-related factors in the Company's decision-making could be subject to increasing scrutiny and objection from such anti-ESG parties. 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.

Changes in U.S. trade policy, including the imposition of tariffs and the resulting consequences, could adversely affect our business, prospects, financial condition and operating results.

There is currently significant uncertainty about the future relationship between the United States and various other countries, including changes that may be implemented by the Trump Administration with respect to trade policies, treaties, tariffs, taxes, and other limitations on cross-border operations. For example, on February 1, 2025, the Trump Administration imposed a 25% tariff on imports from Mexico and Canada into the United States. Although the imposition of such tariffs has been delayed as of the time of this filing, such tariffs and, if enacted, any further legislation or actions taken by the U.S. federal government that restrict trade, such as additional tariffs, trade barriers, and other protectionist or retaliatory measures taken could increase the cost of our products and the components and raw materials that go into making them. Changes in tariffs, trade barriers, price and exchange controls and other regulatory requirements between Mexico and Canada, on one hand, and the U.S., on the other hand could have an adverse effect on our business, prospects, financial condition and operating results, the extent of which cannot be predicted with certainty at this time.

We previously identified material weaknesses in our internal control over financial reporting that could have, had they not been remediated, resulted in material misstatements in our financial statements and caused us to fail to meet our reporting and financial obligations.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis.

In September 2024, the Company received a notification from a third party suggesting that a mid-level employee (the "subject employee") was engaged in inappropriate procurement practices. In response, the Audit Committee of the Company's Board of Directors (the "Audit Committee") conducted a review of such alleged practices by engaging independent external legal counsel to assist in reviewing the matter and determining the extent of such activities. Such review with external legal counsel did not identify nor implicate other current or former employees and the subject employee was separated from the Company. The Audit Committee also did not identify any related material errors in the Company's historical financial statements.

However, in the course of its review, the Company identified two material weaknesses. The first material weakness identified was due to our inability to rely on the review control performed by the subject employee with respect to the estimated decommissioning costs incorporated into the asset retirement obligations recognized in our consolidated financial statements. As such, we could not rely on the subject employee's judgment in the operation of the review control, which is performed upon acquisition of oil and gas assets subject to the asset retirement obligation and when costs are incurred and reassessed. Although the review of such costs was a task unrelated to the reported conduct subject to our review, we nevertheless determined that the concerns raised regarding the subject employee's reliability made it inappropriate to have relied on such subject employee's judgment in the review function. The second material weakness identified was due to inappropriate segregation of duties without designing and maintaining effective monitoring controls over the timely review of expenditures associated with asset retirement obligation spending, capital expenditures and lease operating expenses.

As more fully disclosed under Part II, Item 9A. Controls and Procedures of this Annual Report, our management, with the participation of our interim principal executive officer and principal financial officer, conducted an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2024. Based on that evaluation, our interim CEO and Chief Financial Officer ("CFO") concluded that our disclosure controls and procedures were effective as of December 31, 2024. Additionally, our management concluded that its internal control over financial reporting was effective as of December 31, 2024.

Management, under the oversight of our Audit Committee, took steps to fully remediate the material weaknesses as described more fully in Part II, Item 9A. Controls and Procedures of this Annual Report.

We can give no assurance that additional material weaknesses will not arise in the future. The development of any new material weaknesses in our internal control over financial reporting could result in material misstatements in our consolidated financial statements and cause us to fail to meet our reporting and financial obligations, which in turn could have a negative impact on our financial condition, results of operations or cash flows, restrict our ability to access the capital markets, require significant resources to correct the material weaknesses or deficiencies, subject us to fines, penalties or judgments, harm our reputation or otherwise cause a decline in both investor confidence and the market price of our stock.

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 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 "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 IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information on the issuance of the 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. In addition, there is an availability cap in our Bank Credit Facility such that, if the aggregate exposure of all lenders under the Bank Credit Facility equals or exceeds a certain amount (which amount is currently below the borrowing base) at any time, the approval of lenders holding at least two-thirds of the aggregate commitments is required to make any additional loans or issuance of any additional letters of credit. 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 may not 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 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.

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

As of February 19, 2025, Control Empresarial, an entity controlled by the family of Carlos Slim Helú (collectively, the “Slim Family”) beneficially owned and possessed voting power of approximately 24.2% of our outstanding 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 influence a sale of our company. 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.

On December 16, 2024, we entered into a cooperation agreement (“Cooperation Agreement”) with Control Empresarial. Pursuant to the Cooperation Agreement, Control Empresarial and its affiliates agreed they would not acquire, agree or seek to acquire or make any proposal or offer to acquire, or announce any intention to acquire, directly or indirectly, beneficially or otherwise, any voting securities of the Company (other than in connection with a stock split, stock dividend or similar corporate action initiated by the Company) that exceeds 25% of the outstanding voting shares of the Company during the term of the Cooperation Agreement which expires on December 16, 2025. The Cooperation Agreement does not contain any other voting or other limitations.

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, (ii) the inability to obtain requisite lender approval for additional loans or letters of credit above the availability cap or (iii) 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 America 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 America, 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 America 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, 2024, we have accrued \$5.5 million and \$14.5 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 Note 15 — *Commitments and Contingencies* for more information.

We may not realize the anticipated benefits from our current assets 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 America 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 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 assets and future acquisitions expose us to potentially significant liabilities, including P&A liabilities.

Successful leasing and 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 properties we expect to lease or acquire. 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 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. See Part I, Item 3. Legal Proceedings for more information.

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 Delaware General Corporation Law ("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 are entitled to rights with respect to registration of approximately 17.9 million shares of our common stock (representing approximately 10.0% of the outstanding shares of our common stock as of February 19, 2025) under the Securities Act pursuant to certain registration rights agreements. In the event a large number of shares of our common stock are sold in the public market, such sales could reduce the trading price of our shares of common stock.

In the future, we may also issue securities if we need to raise capital in connection with a capital raise or as consideration to finance any acquisitions. The number of shares of our common stock issued in connection with such an offering could constitute a material portion of our then-outstanding shares of our common stock and result in dilution of the voting power of our current stockholders and negatively impact the trading price of our common stock.

Actions of any activist stockholders or others could materially and adversely affect our business, results of operations and stock price.

We may become subject to actions or proposals from stockholders or others that may not align with our business strategies or the interests of our other stockholders. On December 16, 2024, we entered into the Cooperation Agreement with Control Empresarial. There can be no assurance that we may not become subject to future activities initiated by stockholders. Actions taken by the Board and management in seeking to maintain constructive engagement with certain stockholders may not be successful to prevent the occurrence of stockholder campaigns, and responding to such actions can be costly and time-consuming, disrupt our business and operations, and divert the attention of the Board, management, and employees from the pursuit of our business strategies. The Company has incurred, and may in the future incur, expenses related to stockholder matters, and future stockholder activism activities could interfere with our ability to execute our strategic plan. Activist stockholders or others may create perceived uncertainties as to the future direction of our business or strategy, which may be exploited by our competitors and may make it more difficult to attract and retain qualified personnel and potential customers, and may affect our relationships with current customers, vendors, investors and other third parties. In addition, a proxy contest for the election of directors at an annual meeting would require us to incur significant legal fees and proxy solicitation expenses and require significant time and attention by management and our Board. In connection with any activist campaign, we may choose to initiate, or may become subject to, litigation, which would serve as a further distraction to our Board, management and employees and would require us to incur additional costs. We have previously adopted, and may again in the future choose to adopt, a stockholder rights agreement, which, if adopted, could have certain anti-takeover effects. Our stock price could also be subject to significant fluctuations or otherwise be adversely affected by the events, risks and uncertainties of any stockholder activism.

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. Going forward, we are committed to conducting these evaluations at least annually. 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 cybersecurity training, simulated phishing exercises and awareness campaigns. We conduct employee training bi-annually, and point-in-time training for any phishing failures. We have implemented software and processes and currently use a managed service 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 CFO and Executive Vice President ("EVP") 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 EVP. In addition, our Director of Information Technology has a direct line of communication with the Office of the Interim Chief Executive Officer 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 — The energy sector's growing reliance on information and operational technology to manage critical business functions has significantly increased the exposure to cybersecurity threats. The rising frequency and sophistication of cyber incidents, whether resulting from deliberate attacks or accidental breaches, pose substantial risks to the energy industry. As these threats continue to evolve, effectively preventing, detecting, mitigating, and responding to cyber incidents has become an ongoing and increasingly complex challenge. Regulatory compliance adds another layer of complexity, particularly as cybersecurity reporting and disclosure requirements continue to evolve. These regulations require prompt and detailed disclosures of material cyber incidents, demanding significant resources and well-structured internal processes to maintain compliance. Failure to meet these obligations could lead to legal penalties, heightened regulatory oversight, and reputational harm. Additionally, the constantly shifting regulatory landscape may introduce overlapping or conflicting requirements, further complicating compliance efforts. To minimize potential risks, it is essential to closely monitor these developments and incorporate them into our cybersecurity and regulatory compliance strategies.

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. Although we believe we have implemented comprehensive cybersecurity measures, no security program is infallible. For additional information about cybersecurity risks, 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.

On June 13, 2024, Equinor USA E&P Inc. (f/k/a Statoil USA E&P, Inc., and f/k/a Norsk Hydro USA Oil & Gas, Inc.) ("Equinor") filed a complaint against Talos ERT LLC ("Talos ERT") in the U.S. District Court for the Southern District of Texas, seeking to recover decommissioning and P&A expenses on a certain Gulf of America lease, Mississippi Canyon 941 ("MC 941 Lease"). Equinor's claim rests upon a purported indemnity set forth in a 2006 conveyance instrument in which a former affiliate of Equinor, Hydro Gulf of Mexico, LLC ("Hydro GOM"), sold a 25% interest in the MC 941 Lease to Energy Resource Technology GOM, Inc. ("ERT") (n/k/a Talos ERT). That 25% lease interest was then conveyed to ATP Oil & Gas, Inc. a few months later. The interest was sold several times thereafter, including in 2017, when Equinor reacquired 100% of the MC 941 Lease. Production is continuing from the MC 941 Lease, and as a result, Equinor is seeking decommissioning costs not yet incurred and thus for unknown and unspecified amounts. On September 23, 2024, Talos ERT filed an answer denying all material allegations in Equinor's complaint and asserting a counterclaim for declaratory relief. Talos ERT's counterclaim relies upon indemnities provided pursuant to subsequent transactions of the 25% interest, which Talos ERT asserts Equinor assumed directly or owes as burdens running with the land that it acquired. Talos ERT's counterclaim seeks a declaration that Equinor owes Talos ERT reimbursements for all decommissioning costs and Talos ERT's legal fees in the litigation. On January 10, 2025, Equinor amended its complaint, expanding the scope of the alleged decommissioning obligations to include the Titan floating platform that was placed on location at the MC 941 Lease, years after ERT sold its interest in the MC 941 Lease in 2006, and the full cost to plug and abandon all wells on the MC 941 Lease. Talos ERT will continue to vigorously defend against Equinor's claims and pursue its counterclaim. The trial is currently scheduled for 2026, although Talos ERT intends to file dispositive motions before then.

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. The Company paid the judgment of $14.4 million, inclusive of Mr. Dunwoody's legal fees and interest, during the three months ended March 31, 2024.

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. Plaintiffs filed motions to remand the cases back to state court, which were granted by the federal district court on December 13, 2023. The defendants that filed the removals have appealed the orders of remand. The appeals do not stay the state court proceedings. Since remand, the three Jefferson Parish state court cases involving Stone have been relatively dormant, but one was recently set for trial in October 2026.

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 "District Court"). The plaintiffs 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 (the "Fifth Circuit") on December 15, 2022, and on December, 22, 2022, plaintiffs filed a motion in federal court to re-open the lawsuit. Plaintiffs filed motions to remand, which the District Court granted, along with the defendants' motion to stay the remand order pending appeal. On April 18, 2023, the District Court entered an order denying the defendants' motion for reconsideration of the District Court order to remand and granted the defendants' motion to stay the judgment remanding the matters to state court, pending resolution of the defendants' lawsuit in the Fifth Circuit. On May 4, 2023, the District Court denied the plaintiffs' motion to lift stay pending appeal. In May 2023, the Fifth Circuit entered an order granting the defendants' motion to stay further proceedings pending resolution of a related appeal between Plaquemines Parish and BP America Production Co., among others, which the Fifth Circuit designated as the lead appeal. In the lead appeal proceedings, in May 2024, the Fifth Circuit affirmed the lower courts' orders and remanded the cases to state court. Following denial of the defendants' petition for rehearing on November 25, 2024, the Fifth Circuit stayed further proceedings pending resolution of the petition for writ of certiorari in a related appeal, which was filed with the Supreme Court of the United States in February 2025.

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 15 — *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 19, 2025, there were approximately 209 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

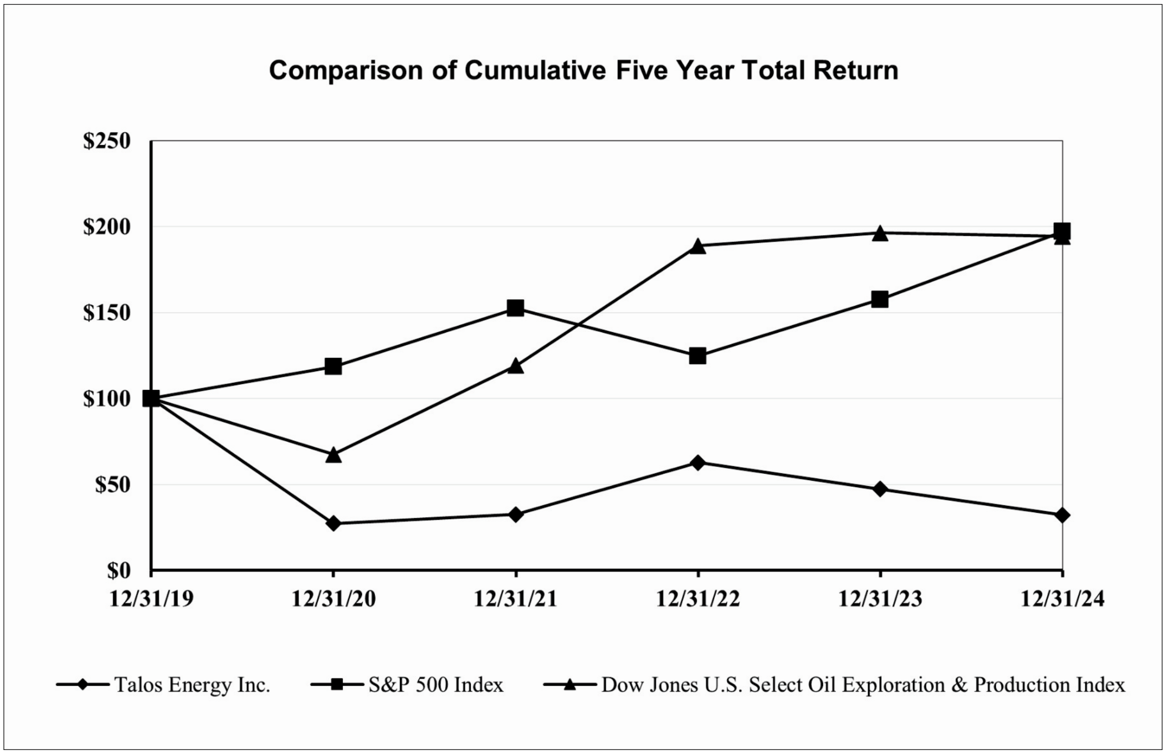
See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding securities authorized for issuance under equity compensation plans.

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. On July 22, 2024, our Board authorized an additional $150.0 million of our previously approved limit increasing the amount remaining under our authorized plan to $159.6 million. As of December 31, 2024, there was approximately $157.4 million remaining under the authorized program. 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. All repurchased shares are held in treasury. 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, 2024.

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, 2019 through December 31, 2024. The graph assumes that $100 was invested in our common stock and each index on December 31, 2019 and that dividends were reinvested.



	2019	2020	2021	2022	2023	2024
Talos Energy Inc.	$ 100	$ 27	$ 33	$ 63	$ 47	$ 32
S&P 500 Index	$ 100	$ 118	$ 152	$ 125	$ 158	$ 197
Dow Jones U.S. Exploration & Production Index	$ 100	$ 68	$ 119	$ 189	$ 196	$ 194

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 2024 and 2023 items and year-to-year comparisons between 2024 and 2023. Discussions of 2022 items and year-to-year comparisons between 2023 and 2022 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, 2023 filed with the SEC on February 29, 2024.

Our Business

We are a technically driven, innovative, independent energy company focused on maximizing long-term value through our Upstream business in the U.S. Gulf of America and offshore Mexico. We leverage decades of technical and offshore operational expertise to acquire, explore, and produce assets in key geological trends while maintaining a focus on safe and efficient operations, environmental responsibility and community impact.

We have historically focused our operations in the U.S. Gulf of America 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 an 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 America results in an asset profile that differentiates us from the typical shale-driven onshore exploration and production companies. Completion of the QuarterNorth Acquisition added 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 America company, diversification outside of our existing operational areas is always a possibility.

The U.S. Energy Information Administration ("EIA") expects downward oil price pressures over much of the next two years, as they expect that global oil production will grow more than global oil demand. The EIA also expects the Henry Hub gas spot price to generally rise over the next two years up from a historically low average in 2024 due to growth in demand that outpaces production growth.

Some energy policy changes can be expected under the Trump Administration. President Trump's energy priorities include energy independence and lowering energy costs. His proposals seek to increase domestic production of oil and gas. Some of the proposals can be carried out by executive action or through the regulatory process, while others, such as changes to legislation, would require congressional action. Meanwhile, changes in certain tax policies could also impact the oil and gas industry. Easing monetary policies, like lowering interest rates, typically lead to an increase in oil prices by stimulating economic growth and increasing demand for energy. Geopolitical tensions, particularly in the main producing regions, such as the Middle East, will continue to influence prices. While these tensions pose risks, they are mitigated by the ability of OPEC Plus to manage supply. The group has delayed oil production increases until April 2025 and prolonged the complete reversal of cuts by a year, until the end of 2026.

We remain exposed to potential operational disruptions from weather-related events in the U.S. Gulf of America. The first long-range forecast for the 2025 Atlantic hurricane season was released on December 10, 2024, with Tropical Storm Risk projecting there could be 15 tropical storms, 7 hurricanes, and 3 intense hurricanes for the 2025 Atlantic hurricane season, which would be roughly aligned with the 30-year norm.

We recently announced that the Katmai West #2 well was drilled significantly under budget and ahead of schedule. Completion activities are ongoing and we expect production to commence late in the second quarter of 2025. We anticipate production to commence from our Sunspear well late in the second quarter of 2025.

Significant Developments

The following encompasses significant developments since the filing of our Annual Report on Form 10-K for year ended December 31, 2023:

Cooperation Agreement — On December 16, 2024, we entered into the Cooperation Agreement with Control Empresarial. Pursuant to the Cooperation Agreement, Control Empresarial agreed that during the term of the Cooperation Agreement that it would not acquire, agree or seek to acquire or make any proposal or offer to acquire, or announce any intention to acquire, directly or indirectly, beneficially or otherwise, any voting securities of the Company (other than in connection with a stock split, stock dividend or similar corporate action initiated by us) if, immediately after such acquisition, Control Empresarial and the other members of its investor group, collectively, would, in the aggregate, beneficially own more than 25.0% of the outstanding shares of any class of voting securities of the Company. The Cooperation Agreement expires December 16, 2025, but is subject to early termination upon the occurrence of certain events described in the Cooperation Agreement. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Related Party Transactions* for additional information on Control Empresarial.

Agreement to Sell Additional Stake in Zama Asset — On December 16, 2024, we entered into an agreement to sell an additional 30.1% equity interest in Talos Mexico to Zamajal, a subsidiary of Carso, for $49.7 million in cash consideration with an additional $33.1 million contingent on first oil production from the Zama Field (the “Incremental Mexico Equity Sale”). The Incremental Mexico Equity Sale is expected to close during 2025 upon the satisfaction of customary closing conditions and the receipt of all regulatory approvals. After consummation of the Incremental Mexico Equity Sale, Talos Mexico, which currently holds a 17.4% interest in the Zama field, will be owned 20.0% by the Company and 80.0% by Zamajal. While the Company anticipates the Incremental Mexico Equity Sale will close in 2025, there can be no assurance that all of the conditions to closing, including obtaining necessary regulatory approvals, will be satisfied. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments* for additional information on the Incremental Mexico Equity Sale and Note 14 — *Related Party Transactions* for additional information on Carso.

Limited Duration Stockholder Rights Agreement — On October 1, 2024, our Board adopted a stockholder rights agreement (the “Rights Agreement”) and declared a dividend distribution of one preferred share purchase right (“Right”) on each outstanding share of our common stock, par value $0.01 per share, which became payable on October 11, 2024. In adopting the Rights Agreement, the Board noted, in particular, the continued accumulation of approximately 24.0% of shares of Talos common stock by Control Empresarial. In connection with entering into the Cooperation Agreement, we entered into the First Amendment to the Rights Agreement (the “Amendment”). The Amendment accelerated the expiration of the Rights from the close of business on October 1, 2025 to the close of business on December 17, 2024. Accordingly, the Rights issued under the Rights Agreement expired and are no longer outstanding.

See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 10 — *Stockholders’ Equity* for more information on both the Rights Agreement and Amendment and Note 14 — *Related Party Transactions* for additional information on Control Empresarial.

Chief Executive Officer Transition — On August 29, 2024, Timothy S. Duncan departed his role as President and Chief Executive Officer of the Company. The Company also announced that Joseph A. Mills would serve as Interim Chief Executive Officer and President, effective as of August 29, 2024. On January 5, 2025, Mr. Mills informed the Board that he was resigning from his position as Interim Chief Executive Officer and President and as a member of the Board, effective immediately. Effective as of January 6, 2025, the Board created an Office of the Interim Chief Executive Officer (the “Office of the Interim CEO”) and appointed the following three senior executives to serve, in addition to their existing roles, as interim Co-Presidents and as members of the Office of the Interim CEO: (i) Mr. William S. Moss, III, Executive Vice President, General Counsel and Secretary of the Company; (ii) Mr. Sergio L. Maiworm, Jr., Executive Vice President and Chief Financial Officer of the Company; and (iii) Mr. John B. Spath, Executive Vice President and Head of Operations of the Company (such appointees collectively, the “Members”). Each Member is serving individually as Interim Co-President, managing the function of the Office of the Interim CEO, and serving at the discretion of the Board until the earlier of (a) the effective start date of a permanent Chief Executive Officer and (b) with respect to each such Member, such Member’s successor has been duly appointed and qualified or until his death, disability, resignation or removal. The Office of the Interim CEO reports to the Board and performs the duties and responsibilities of the role of the Chief Executive Officer on an interim basis while the search for a permanent Chief Executive Officer was being concluded by the Board, with Mr. Moss designated as interim Chief Executive Officer and the principal executive officer of the Company on January 6, 2025. On February 3, 2025, the Company announced that Mr. Paul R. Goodfellow had been selected to serve as President and Chief Executive Officer, principal executive officer and member of the Board, effective as of March 1, 2025. The Office of the Interim CEO will dissolve at such time that Mr. Goodfellow takes office.

Acquisition of Working Interests in Monument Oil Discovery — We executed two separate definitive agreements to acquire a collective 21.4% non-operated working interest in the Monument oil discovery (“Monument Project”) in the Deepwater U.S. Gulf of America located on certain Walker Ridge lease blocks in late July 2024 and early August 2024. First production is expected from the Monument Project by late 2026. On February 20, 2025, we executed a definitive agreement to acquire an additional 8.3% non-operated working interest in the Monument Project for $6.3 million, excluding customary effective date adjustments. An additional aggregate $6.3 million will be paid after certain milestones are achieved. The Company expects to close in March 2025. See additional information in Part IV, Item 1. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures.*

***Talos Low Carbon Solutions Divestiture* —** On March 18, 2024, we entered into a definitive agreement relating to and subsequently completed the sale of our wholly owned subsidiary, Talos Low Carbon Solutions LLC, to TotalEnergies E&P USA, Inc. for a purchase price of $125.0 million plus customary reimbursements and adjustments, combined totaling an aggregate of approximately $142.0 million (the "TLCS Divestiture"). The TLCS Divestiture included Talos's entire CCS business, including its equity investment in three projects along the U.S. Gulf Coast: Bayou Bend CCS LLC ("Bayou Bend"); Harvest Bend CCS LLS; and Coastal Bend CCS LLC. The TLCS Divestiture also entitles Talos to certain contingent payments, of which $4.7 million was received during the year ended December 31, 2024 and $12.5 million is expected to be received during the year ended December 31, 2025. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***QuarterNorth Acquisition Completed* —** On March 4, 2024, we completed the acquisition of QuarterNorth Energy Inc. ("QuarterNorth"), a privately-held U.S. Gulf of America exploration and production company (the "QuarterNorth Acquisition") for consideration consisting of (i) $1,247.4 million in cash and (ii) 24.3 million shares of the Company's common stock valued at $322.6 million. The cash payment was partially funded with a January 2024 underwritten public offering of 34.5 million shares of the Company's common stock, borrowings under the Bank Credit Facility and the Senior Notes. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures,* Note 8 — *Debt* and Note 10 — *Stockholders' Equity* for additional information.

***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. During the year ended December 31, 2023 and six months ended June 30, 2024, we repurchased 3.4 million shares for $47.5 million and 3.8 million shares for $42.9 million, respectively. On July 22, 2024, our Board authorized an additional $150.0 million to our previously approved limit increasing the amount remaining under our authorized plan to $159.6 million. During the three months ended September 30, 2024, we repurchased 0.2 million shares for $2.2 million. There were no shares of common stock repurchased during the three months ended December 31, 2024. We have repurchased an aggregate of 7.4 million shares under our authorized program for a total of $92.6 million resulting in approximately $157.4 million remaining under our authorized program as of December 31, 2024. 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.

***QuarterNorth Acquisition* —** On March 4, 2024, we completed the acquisition of QuarterNorth. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

***EnVen Acquisition* —** On February 13, 2023, we acquired EnVen Energy Corporation ("EnVen"), a private operator in the Deepwater U.S. Gulf of America (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 Helix Producer I ("HP-I") that is operated by Helix Energy Solutions Group, Inc ("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, 2024, Helix dry-docked the HP-I. After conducting sea trials, production resumed in mid-June, resulting in a total shut-in period of 52 days. The shut-in resulted in an estimated deferred production of approximately 1.2 MBoepd for the year ended December 31, 2024 based on production rates prior to the shut in. The next dry-dock is scheduled for the first half of 2027 with a projected shut-in period of approximately 45 days.

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, 2024 through December 31, 2024, the daily spot prices for NYMEX WTI crude oil ranged from a high of $87.69 per Bbl to a low of $66.73 per Bbl and the daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $13.20 per MMBtu to a low of $1.21 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, 2024.

The EIA published its February 2025 Short-Term Energy Outlook on February 11, 2025. The EIA expects the NYMEX WTI spot price will average $70.62 per Bbl in 2025 compared to an average of $76.60 per Bbl in 2024. The current forecast for 2026 is $62.46 per Bbl. Following some initial upward price pressure in early 2025, the EIA expects that crude oil prices will generally decline from mid-2025 through the end of 2026 as growth in global oil production outpaces growth in oil demand. The EIA does not presently anticipate the tariffs put forward in President Trump's February 1, 2025 executive order would significantly affect global oil supply. However, the possibility of future tariffs and the new sanctions on Russia are sources of uncertainty for oil prices going forward. The EIA also expects natural gas prices to average $3.79 per MMBtu in 2025, and rise to an average of $4.16 per MMBtu in 2026, up from an average of $2.19 per MMBtu in 2024. Natural gas inventories are expected to remain at or below previous five-year averages during the forecast period putting upward pressure on natural gas prices. Over the next two years, the EIA expects that natural gas demand in the U.S. will generally grow by more than natural gas supply. Exports are the leading source of natural gas demand growth in the EIA forecast. Two new LNG export facilities—Plaquemines LNG and Corpus Christi LNG Stage 3—started producing liquefied natural gas in December 2024.

***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. Inflation 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. In 2022 and 2023, the Fed raised its benchmark interest rate 11 times. The Fed wants inflation to return to its 2% goal over time, and even though inflation has declined, it is still high in absolute terms. The Fed lowered its benchmark interest rate three times between September and December 2024 by an aggregate 100 basis points to a new range of 4.25%-4.50% from its 23-year high of 5.25% to 5.50%. In January 2025, the Fed left its benchmark interest rate unchanged as the Fed seeks to gauge where inflation is headed and what policies President Trump may pursue. For example, higher tariffs and tax cuts could push inflation higher, while deregulation could possibly reduce it. 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 2024, 2023 and 2022 our ceiling test computations for our U.S. oil and gas properties did not result in a write down. At December 31, 2024, the Company's ceiling test computation was based on SEC pricing of $75.51 per Bbl of oil, $2.45 per Mcf of natural gas and $21.91 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, 2024 and ending December 1, 2024 used in the determination of the SEC pricing was 10% lower, resulting in $67.95 per Bbl of oil, $2.23 per Mcf of natural gas and $19.79 per Bbl of NGLs, while all other factors remained constant, our oil and natural gas properties would have been impaired by approximately $420.0 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.

***Financial Assurance Requirements* —** On April 15, 2024, BOEM issued a final rule related to supplemental financial assurance requirements in the OCS entitled "Risk Management and Financial Assurance for OCS Lease and Grant Obligations." This rule significantly increases the amount of new supplemental financial assurance required from certain lessees and grant holders conducting operations on the OCS. The final rule provides that BOEM will no longer consider or rely upon the financial strength of predecessors in title in determining whether, or how much, supplemental financial assurance will be required by current lessees and grant holders. The final rule, which became effective on June 29, 2024, adopts a three-year phased compliance period to fully comply with BOEM's supplemental financial assurance demand. Per BOEM's June 28, 2024 news release, BOEM indicated it may take up to 24 months from that date to complete the processing of financial assurance demands. The final rule was challenged in the U.S. District Court for the Western District of Louisiana by multiple oil and gas industry groups and the States of Mississippi, Louisiana, and Texas on June 17, 2024. The implementation of the final rule is not currently stayed and the outcome of these challenges remains uncertain. However, the Trump Administration may seek to suspend, revise or rescind the rule pursuant to Interior Secretary Burgum's Secretarial Order 3418 dated February 3, 2025, although the substance and timing of such action, if any, cannot be predicted at this time.

If the final rule is not suspended, revised or rescinded, or if it is not overturned pursuant to the ongoing litigation, we may be unable to comply with orders from BOEM to provide additional surety bonds or other financial assurances. Consequently, 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, liquidity and financial condition. Moreover, regardless of the final rule, 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.

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.

Financial Assurance Market Outlook — As a result of adverse developments in restructurings and bankruptcies of companies operating in the OCS, a number of surety companies have left the offshore surety market, which has materially reduced the availability of surety bonds for projects in the OCS and may reduce the ability of companies operating in the OCS to obtain bonding without posting collateral. As a result, there may not be sufficient surety bond capacity available for companies in the OCS to comply with BOEM's financial assurance requirements or otherwise if the final rule is not suspended, revised or rescinded or if it is not overturned pursuant to the ongoing litigation. In addition to BOEM's financial assurance requirements, companies with whom we partner or from whom we wish to acquire assets may require that we provide financial assurance, such as surety bonds, to provide assurance that our decommissioning obligations associated with those jointly held or acquired assets can be met in the future. The tightened capacity in the surety market may impact our ability to secure surety bonds at commercially reasonable terms and therefore, our ability to enter into such joint participation or asset acquisition opportunities may be impacted.

Moreover, under our existing and future indemnity agreements, surety companies have the right to demand additional collateral, such as cash or letters of credit, to support existing or future bonds. We cannot provide assurance that we will be able to satisfy collateral demands. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be significantly negatively impacted and we may be required to seek alternative financing in order to continue operations, develop new projects and acquire new assets. These regulatory requirements and market trends could, in the future, result in significantly increased costs on our operations, reduced cash flows and liquidity and consequently have a material adverse effect on our business and results of operations.

Deepwater Operations — We have interests in Deepwater fields in the U.S. Gulf of America. 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, Winter Storms and Loop Currents — Since our operations are in the U.S. Gulf of America, we are particularly vulnerable to the effects of hurricanes, tropical storms, winter 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 America, Lease Sales 259 and 261 included in the 2017-2022 Five-Year Leasing 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 America lease sales. The IRA 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 leases on all of our high-bid blocks. Additionally, QuarterNorth was the high bidder on four offshore blocks related to Lease Sale 261 and they were also awarded leases on all of their high-bid blocks.

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 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.

The 2024-2029 Five-Year Leasing Program began on July 1, 2024, and will continue through June 30, 2029, and includes a maximum of three potential oil and gas lease sales in the Gulf of America scheduled to be held in years 2025, 2027 and 2029. It is possible, however, that this program could be delayed by opposing lawsuits that were filed on February 12, 2024 by the American Petroleum Institute and Earthjustice representing multiple environmental groups, both of which are challenging BOEM's actions. Despite these challenges, on April 1, 2024, BOEM announced the availability of the Area Identification for proposed Gulf of America lease sales 262, 263 and 264 pursuant to the 2024-2029 Five-Year Leasing Program. On December 13, 2024, BOEM published its Draft Programmatic Environmental Impact Statement for proposed U.S. Gulf of America lease sales 262, 263 and 264. Lease Sale 262 is tentatively scheduled for 2025. The Trump Administration may seek to take additional action to revise the Five-Year Leasing Program, although the substance and timing of such action cannot be predicted.

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,		
	2024	2023	2022
Oil	92 %	93 %	83 %
Natural gas	5 %	5 %	14 %
NGL	3 %	2 %	3 %

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 America 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,		
	2024	**2023**	**2022**
Oil:			
NYMEX WTI high per Bbl	$ 85.35	$ 89.43	$ 114.84
NYMEX WTI low per Bbl	$ 69.95	$ 70.25	$ 76.44
Average NYMEX WTI per Bbl	$ 76.54	$ 77.63	$ 94.79
Average oil sales price per Bbl (including commodity derivatives)	$ 75.07	$ 73.59	$ 68.40
Average oil sales price per Bbl (excluding commodity derivatives)	$ 75.01	$ 75.17	$ 93.75
Natural Gas:			
NYMEX Henry Hub high per MMBtu	$ 3.18	$ 3.27	$ 8.81
NYMEX Henry Hub low per MMBtu	$ 1.49	$ 2.14	$ 4.38
Average NYMEX Henry Hub per MMBtu	$ 2.19	$ 2.54	$ 6.42
Average natural gas sales price per Mcf (including commodity derivatives)	$ 2.65	$ 3.32	$ 5.30
Average natural gas sales price per Mcf (excluding commodity derivatives)	$ 2.57	$ 2.60	$ 7.06
NGLs:			
NGL realized price as a % of average NYMEX WTI	27 %	23 %	35 %

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 plug, 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, 2024	Year Ended December 31, 2023	Change
Revenues:			
Oil	$ 1,806,148	$ 1,357,732	$ 448,416
Natural gas	105,528	68,034	37,494
NGL	61,892	32,120	29,772
Total revenues	$ 1,973,568	$ 1,457,886	$ 515,682
Production Volumes:			
Oil (MBbls)	24,078	18,062	6,016
Natural gas (MMcf)	41,078	26,194	14,884
NGL (MBbls)	2,969	1,767	1,202
Total production volume (MBoe)	33,893	24,195	9,698
Daily Production Volumes by Product:			
Oil (MBblpd)	65.8	49.5	16.3
Natural gas (MMcfpd)	112.2	71.8	40.4
NGL (MBblpd)	8.1	4.8	3.3
Total production volume (MBoepd)	92.6	66.3	26.3
Average Sale Price per Unit:			
Oil (per Bbl)	$ 75.01	$ 75.17	$ (0.16)
Natural gas (per Mcf)	$ 2.57	$ 2.60	$ (0.03)
NGL (per Bbl)	$ 20.85	$ 18.18	$ 2.67
Price per Boe	$ 58.23	$ 60.26	$ (2.03)
Price per Boe (including realized commodity derivatives)	$ 58.37	$ 59.86	$ (1.49)

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	$ (3,807)	$ 452,223	$ 448,416
Natural gas	(1,204)	38,698	37,494
NGL	7,920	21,852	29,772
Total revenues	$ 2,909	$ 512,773	$ 515,682

***Volumetric Analysis* —** Production volumes increased by 26.3 MBoepd to 92.6 MBoepd for the year ended December 31, 2024. The increase was primarily due to 21.9 MBoepd in production from the oil and natural gas assets acquired in the QuarterNorth Acquisition that closed in early March 2024 as well as 2.2 MBoepd from the EnVen Acquisition that closed mid-first quarter of 2023. Additionally, we recognized incremental 10.0 MBoepd of production from the Venice and Lime Rock wells, which tie back to our Ram Powell facility and commenced initial production late in the fourth quarter of 2023. These increases were partially offset by a decrease of 4.7 MBoepd due to well performance and natural production declines primarily in our Phoenix Field, Green Canyon 18 Field and Pompano Field. Additionally, there was a decrease of 1.2 MBoepd of production due to disruptions from weather events in the U.S. Gulf of America as well as approximately 1.2 MBoepd of deferred production resulting from third party downtime associated with the HP-I dry-dock in our Phoenix 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,	
	2024	2023
Lease operating expenses	$ 566,041	$ 389,621
Lease operating expenses per Boe	$ 16.70	$ 16.10

Total lease operating expenses for the year ended December 31, 2024 increased by approximately $176.4 million, or 45%. The increase is primarily related to lease operating expenses of $147.0 million incurred in connection with assets acquired from the QuarterNorth Acquisition. Additionally, there was a $58.6 million increase in facility and workover expenses primarily attributable to the HP-I and major well workover expenses at the Phoenix Field and Garden Banks 506 Field associated with our historical operations.

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,	
	2024	2023
Depreciation, depletion and amortization	$ 1,023,558	$ 663,534

Depreciation, depletion and amortization expense for the year ended December 31, 2024 increased by approximately $360.0 million, or 54%. This increase was primarily driven by the increased production volumes of 26.3 MBoepd discussed above and to a lesser extent an increase of $2.87 per Boe, or 11% in the depletion rate on our proved oil and natural gas properties due to our amortization base increasing disproportionately to the increase in our reserve base. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures*.

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,	
	2024	2023
Upstream Segment	$ 191,063	$ 145,960
CCS Segment	10,454	12,533
Total general and administrative expense	$ 201,517	$ 158,493
Upstream general and administrative expense per Boe	$ 5.64	$ 6.03

General and administrative expense for the year ended December 31, 2024, increased by approximately $43.0 million, or 27%. This increase was primarily related to the Upstream Segment transaction costs, severance costs and additional general and administrative expenses related to the QuarterNorth Acquisition of $43.6 million or $1.29 per Boe. The CCS Segment reflects an increase in transaction costs and severance costs of $7.9 million related to the TLCS Divestiture. There was an increase to the Upstream Segment of $5.0 million in severance expense related to the departure of the Company's former President and Chief Executive Officer as discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Employee Benefits Plans and Share-Based Compensation*. Additionally, there was an increase in contractor and payroll expenses due to an increase in employee headcount primarily related to the QuarterNorth Acquisition. These increases were partially offset by a decrease in the Upstream Segment transaction costs for the EnVen Acquisition of $40.6 million or $1.68 per Boe. Additionally, the CCS Segment expenses decreased by $10.0 million due to the TLCS Divestiture. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for further discussion.

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,	
	2024	2023
Accretion expense	$ 117,604	$ 86,152
Other operating (income) expense	$ (109,454)	$ (52,155)
Interest expense	$ 187,638	$ 173,145
Price risk management activities (income) expense	$ 1,458	$ (80,928)
Equity method investment (income) expense	$ 10,289	$ 3,209
Other (income) expense	$ 44,930	$ (12,371)
Income tax (benefit) expense	$ 5,003	$ (60,597)

Accretion Expense — During the year ended December 31, 2024, we recorded $117.6 million of accretion expense compared to $86.2 million during the year ended December 31, 2023. The change is primarily the result of the increase in accretion associated with the higher asset retirement obligations subject to accretion expense including $15.4 million of incremental accretion expense related to the asset retirement obligations assumed as part of the QuarterNorth 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, 2024, we recognized a gain of $100.4 million on the TLCS 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 $8.6 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, 2023, we recognized a gain of $66.2 million on the 2023 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.

Interest Expense — During the year ended December 31, 2024, we recorded $187.6 million of interest expense compared to $173.1 million during the year ended December 31, 2023. The change is primarily a result of an increase in debt outstanding offset by a lower rate of interest on these instruments. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*. Additionally, there was an increase of $4.9 million of fees associated with the unutilized bridge loan during the year ended December 31, 2024. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for further discussion.

Price Risk Management Activities — Price risk management activities for year ended December 31, 2024 resulted in a decrease of approximately $82.4 million, or 102%. The expense of $1.5 million for the year ended December 31, 2024 consisted of $6.2 million in non-cash losses from the decrease in the fair value of our open derivative contracts offset by $4.7 million in cash settlement gains. 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.

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 2026, 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) Expense — During the year ended December 31, 2024, we recorded equity losses of $10.3 million. 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 U.S.A. Inc. ("Chevron"). 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, 2024, we recorded a $60.3 million loss on extinguishment of debt in conjunction with the redemption of the 12.00% Second-Priority Senior Secured Notes due 2026 (the "12.00% Notes") and 11.75% Senior Secured Second Lien Notes due 2026 (the "11.75% Notes"). See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information.

Income Tax Benefit (Expense) — During the year ended December 31, 2024, we recorded $5.0 million of income tax expense compared to $60.6 million of income tax benefit during the year ended December 31, 2023. The expense of $5.0 million for the year ended December 31, 2024 is primarily due to a non-cash tax expense of $38.2 million related to the effect of a change in state tax rate, offset with a non-cash tax benefit of $20.3 million related to the partial release of the valuation allowance for certain of our state deferred tax assets and an income tax benefit of $10.7 million related to current year activity inclusive of permanent differences. For the year ended December 31, 2023, we recorded $106.8 million of income tax benefit related to the release of the valuation allowance for our federal deferred tax assets partially offset with an income tax expense of $31.1 million related to current year activity inclusive of permanent differences. The realization of our deferred tax assets 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 12 — *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 15 — *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,		
	2024	2023	2022
Net income (loss)	$ (76,393)	$ 187,332	$ 381,915
Interest expense	187,638	173,145	125,498
Income tax expense (benefit)	5,003	(60,597)	2,537
Depreciation, depletion and amortization	1,023,558	663,534	414,630
Accretion expense	117,604	86,152	55,995
EBITDA	1,257,410	1,049,566	980,575
Transaction and other (income) expense(1)	(59,022)	(33,295)	(34,513)
Decommissioning obligations(2)	8,559	11,879	31,558
Derivative fair value (gain) loss(3)	1,458	(80,928)	272,191
Net cash received (paid) on settled derivative instruments(3)	4,710	(9,457)	(425,559)
(Gain) loss on debt extinguishment	60,256	—	1,569
Non-cash equity-based compensation expense	14,462	12,953	15,953
Adjusted EBITDA	$ 1,287,833	$ 950,718	$ 841,774

(1) For the year ended December 31, 2024, transaction expenses include $39.1 million in costs related to the QuarterNorth Acquisition, inclusive of $22.2 million in severance expense, $8.5 million in costs related to the TLCS Divestiture, inclusive of a net $3.0 million in severance expense, and $5.0 million in severance expense related to the departure of the Company's President and Chief Executive Officer as discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Employee Benefits Plans and Share-Based Compensation*. 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 expense 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 — *Acquisition and Divestitures* and Note 11 — *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, 2024, the amount includes a gain of $100.4 million related to the TLCS Divestiture and a $9.5 million gain related to an increase in fair value of a service credit acquired via the QuarterNorth Acquisition. For the year ended December 31, 2023, the amount includes a $66.2 million gain on the 2023 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 the Company's investment in Bayou Bend by Chevron of $8.6 million and $1.4 million for the years 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 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 15 — *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 15 — *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 is influenced by changes in the federal funds rate. As interest rates increase, it becomes more expensive to borrow money while interest rate cuts make it less expensive to borrow money. Our working capital deficit has decreased since December 31, 2023 primarily due to increased cash and cash equivalents of $74.5 million and redemption $30.0 million in the current portion of principal amount of the 11.75% Notes using the proceeds from the issuance of the Senior Notes. For additional details on the 11.75% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

Our Bank Credit Facility currently has a borrowing base of $925.0 million but is subject to an $800.0 million availability cap. As of December 31, 2024, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $865.8 million or $990.8 million inclusive of the $125.0 million availability cap requiring certain lender approval. If we are unable to replace proved reserves either through acquisitions or new drilling activity, our borrowing base will likely be reduced at our next redetermination which is expected second quarter of 2025 and our available liquidity may be negatively impacted unless offset by cash generated from our operating activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information.

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.

Capital Expenditures — The following is a table of our capital expenditures, excluding acquisitions, for the year ended December 31, 2024 (in thousands):

U.S. drilling & completions	$	283,779
Asset management[(1)]		109,222
Seismic and G&G, land, capitalized G&A and other		91,059
Total Upstream capital expenditures		484,060
Plugging & abandonment		108,789
Decommissioning obligations settled[(2)]		5,447
Investment in Mexico		5,469
Total Upstream		603,765
Investment in CCS		17,519
Total	$	621,284

(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 15 — *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 2025 Upstream capital spending program of $500.0 million to $540.0 million and plugging & abandonment and decommissioning obligations of $100.0 million to $120.0 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. During the year ended December 31, 2023 and six months ended June 30, 2024, we repurchased 3.4 million shares for $47.5 million and 3.8 million shares for $42.9 million, respectively. On July 22, 2024, our Board authorized an additional $150.0 million to our previously approved limit increasing the amount remaining under our authorized plan to $159.6 million. During the three months ended September 30, 2024, we repurchased 0.2 million shares for $2.2 million. There were no shares of common stock repurchased during the three months ended December 31, 2024. We have repurchased an aggregate of 7.4 million shares under our authorized program for a total of $92.6 million resulting in approximately $157.4 million remaining under our authorized program as of December 31, 2024. 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 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. In the past, there have been proposals to increase the amount of the excise tax 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 2024 based on the fair market value of the stock issued during 2024.

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,	
	2024	2023
Operating activities	$ 962,593	$ 519,069
Investing activities	$ (1,320,279)	$ (512,626)
Financing activities	$ 436,119	$ 85,411

Operating Activities — Net cash provided by operating activities increased $443.5 million in 2024 compared to 2023 primarily attributable to an increase in revenues that was slightly offset by an increase in lease operating expense of $339.3 million. Additionally, there were $4.7 million of net cash settlement receipts on derivative instruments during the year ended December 31, 2024 compared to $9.5 million in net cash settlement payments on derivative instruments during the corresponding period in 2023.

Investing Activities — Net cash used in investing activities increased $807.7 million in 2024 compared to 2023 primarily due to cash paid for acquisitions of $936.2 million, net of cash acquired, of which $916.0 million related to the QuarterNorth Acquisition. Cash proceeds of $146.7 million were received from the TLCS Divestiture during the year ended December 31, 2024 compared to $74.9 million of net proceeds from the 2023 Mexico Divestiture during the corresponding period in 2023. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information. Additionally, cash capital expenditures decreased $52.5 million.

Financing Activities — Net cash provided by financing activities increased $350.7 million in 2024 compared to 2023. During the year ended December 31, 2024, the issuance of the Senior Notes in February 2024 generated $1,217.1 million after deferred financing costs. The net proceeds from the Senior Notes funded the $897.1 million redemption of the 12.00% Notes and the 11.75% Notes and partially funded the cash portion of the QuarterNorth Acquisition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information. Additionally, on January 17, 2024, we entered into an underwritten public offering of 34.5 million shares of our common stock, which generated net proceeds of $387.7 million after deducting underwriting discounts of $15.1 million and offering expenses of $0.8 million. The net proceeds from this equity offering partially funded the cash portion of the QuarterNorth Acquisition. Furthermore, Bank Credit Facility net repayments of $200.0 million were made during the year ended December 31, 2024 due to a management goal to maintain or reduce our leverage ratio coupled with a commodity price environment that supported debt repayments to achieve such goal. We had net borrowings from the Bank Credit Facility of $200.0 million during the corresponding period in 2023 due to the funding of the EnVen Acquisition, working capital needs and capital expenditures.

Overview of Debt Instruments

Financing Arrangements — As of December 31, 2024, total debt, net of discount and deferred financing costs, was approximately $1,221.4 million, comprised of our $1,250.0 million aggregate principal amount of the 9.000% Notes and 9.375% Notes (as defined herein) and no outstanding borrowings under our Bank Credit Facility. We were in compliance with all debt covenants at December 31, 2024. 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 borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter of each year based on a proved reserves report that we deliver to the administrative agent of our Bank Credit Facility. For additional details on our Bank Credit Facility, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

Redemption of the 12.00% Second-Priority Senior Secured Notes—due January 2026 — On February 7, 2024, we redeemed $638.5 million aggregate principal amount of the 12.00% Notes using the proceeds from the issuance of the Senior Notes. For additional details on the 12.00% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

Redemption of the 11.75% Senior Secured Second Lien Notes—due April 2026 — On February 7, 2024, we redeemed $227.5 million aggregate principal amount of the 11.75% Notes using the proceeds from the issuance of the Senior Notes. For additional details on the 11.75% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

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.

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, 2024 (in thousands):

	2025	2026	2027	2028	2029	Thereafter	Total[4]
Long-term financing obligations:							
Debt principal	$ —	$ —	$ —	$ —	$ 625,000	$ 625,000	$ 1,250,000
Debt interest	119,372	119,372	115,976	114,844	86,719	87,891	644,174
Vessel commitments[1]	99,069	—	—	—	—	—	99,069
Derivative liabilities	6,474	3,537	—	—	—	—	10,011
Operating lease obligations	5,656	4,983	4,753	4,610	3,226	1,357	24,585
Finance lease[2]	47,305	19,711	—	—	—	—	67,016
Purchase obligations[3]	40,668	—	—	—	—	—	40,668
Other commitments	19,082	16,493	9,249	10,619	4,465	1,453	61,361
Total contractual obligations[4]	$ 337,626	$ 164,096	$ 129,978	$ 130,073	$ 719,410	$ 715,701	$ 2,196,884

(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) This table does not include our estimated discounted liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $1,149.7 million as of December 31, 2024. 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 15 — *Commitment and Contingencies*.

Performance Obligations — As of December 31, 2024, we had secured performance bonds totaling $1.5 billion primarily related to plugging and abandonment of wells and removal of facilities in the U.S. Gulf of America. Additionally, we had secured letters of credit issued under our Bank Credit Facility totaling $42.4 million. Letters of credit that are outstanding reduce the available revolving credit commitments. See the subsection entitled "— Known Trends and Uncertainties — Financial Assurance Requirements and — Financial Assurance Market Outlook" 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 15 — *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 carrying value of our proved 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. Our reserves at December 31, 2024 were fully engineered by NSAI, while prior year reserve estimates, including as of December 31, 2023 and 2022, were audited by NSAI. See Part I, Items 1 and 2. Business and Properties—Summary of Reserves for further discussion. 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 year ended December 31, 2024 would have increased by an estimated $108.1 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. We estimate the net downward revisions of previous reserve volume estimates accounted for approximately $162.0 million of the standardized measure of our total reserves from December 31, 2023 to December 31, 2024. 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, 2024, 2023 and 2022.

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 P&A and decommission 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.

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.

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

Information on Recently Adopted Accounting Standards that impacted 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.*

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, 2024, our average oil price realizations after the effect of derivatives increased 2% to $75.07 per Bbl from $73.59 per Bbl in the comparable 2023 period. Our average natural gas price realizations after the effect of derivatives decreased 20% during the year ended December 31, 2024 to $2.65 per Mcf from $3.32 per Mcf in the comparable 2023 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 11,642 MBbls of crude oil and 28,245 MMBtu of natural gas at December 31, 2024, with a net derivative asset position of $23.7 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, 2024 (in thousands):

		Oil and Natural Gas Derivatives			
		Ten Percent Increase		Ten Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
Price impact(1)	$ 23,728	$ (61,501)	$ (85,229)	$ 109,219	$ 85,491

(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 $1,250.0 million at December 31, 2024, before unamortized original issue discount and deferred financing costs from our 9.000% Notes and 9.375% Notes, which bears interest at a fixed rate. There were no 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, 2024, our interest rate risk exposure is mitigated as a result of fixed interest rates on 100% of our debt. 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, 2024 and 2023 and for the years ended December 31, 2024, 2023 and 2022, 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 interim 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 interim chief executive officer and chief financial officer have concluded that as of December 31, 2024, our disclosure controls and procedures were effective at a reasonable assurance level.

Our disclosure controls and procedures are designed at a reasonable assurance level to ensure 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, 2024 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.

Remediation Status of Previously Reported Material Weaknesses

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis.

In September 2024, the Company received a notification from a third party suggesting that a mid-level employee (the "subject employee") was engaged in inappropriate procurement practices. In response, the Audit Committee conducted a review of such alleged practices by engaging independent external legal counsel to assist in reviewing the matter and determining the extent of such activities. Such review with external legal counsel did not identify nor implicate other current or former employees and the subject employee was separated from the Company. The Audit Committee also did not identify any related material errors in the Company's historical financial statements.

However, in the course of its review, the Company identified two material weaknesses. The first material weakness identified was due to our inability to rely on the review control performed by the subject employee with respect to the estimated decommissioning costs incorporated into the asset retirement obligations recognized in our consolidated financial statements. As such, we could not rely on the subject employee's judgment in the operation of the review control, which is performed upon acquisition of oil and gas assets subject to the asset retirement obligation and when costs are incurred and reassessed. Although the review of such costs was a task unrelated to the reported conduct subject to our review, we nevertheless determined that the concerns raised regarding the subject employee's reliability made it inappropriate to have relied on such subject employee's judgment in the review function. The second material weakness identified was due to inappropriate segregation of duties without designing and maintaining effective monitoring controls over the timely review of expenditures associated with asset retirement obligation spending, capital expenditures and lease operating expenses.

Inability to rely on the review control performed by the subject employee with respect to the estimated decommissioning costs incorporated into the asset retirement obligations recognized in our consolidated financial statements.

Management, with oversight from the Audit Committee, performed the following to remediate this material weakness:

- The subject employee was separated from the Company on October 25, 2024.
- A qualified person was appointed over business processes related to the review of estimated decommissioning costs.
- Implemented enhanced policies and training relating to defined roles and responsibilities, the appropriate segregation of duties, and the promotion of ethical behavior.

We completed the testing of the design and operating effectiveness of the controls. Based on the results of our testing, as of December 31, 2024, we concluded that the controls are adequately designed, implemented, and have operated effectively for a sufficient period of time to remediate this previously reported material weakness.

Inappropriate segregation of duties without designing and maintaining effective monitoring controls over the timely review of expenditures associated with asset retirement obligation spending, capital expenditures and lease operating expenses.

Management, with oversight from the Audit Committee, performed the following to remediate this material weakness:

- Implemented enhanced policies and training relating to defined roles and responsibilities, the appropriate segregation of duties, and the promotion of ethical behavior.
- Established and enhanced the design, including the precision, of the monitoring control(s) related to expenditures associated with asset retirement obligation spending, capital expenditures and lease operating expenses, and the effective operation of such control(s).

We completed the testing of the design and operating effectiveness of the controls. Based on the results of our testing, as of December 31, 2024, we concluded that the controls are adequately designed, implemented, and have operated effectively for a sufficient period of time to remediate this previously reported material weakness.

Inherent Limitations on Effectiveness of Controls

Control systems, no matter how well conceived and operated, are designed to provide a reasonable, but not an absolute, level of assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints and the benefits of controls must be considered relative to their costs. Because of these inherent limitations in all controls systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Because of the inherent limitations in any control system, misstatements due to error or fraud may occur and not be detected.

Changes in Internal Control over Financial Reporting

As described above, the Company remediated the previously reported material weaknesses noted above. Other than in connection with these remediation steps, 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 2024 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, 2024, 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 2025 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2024.

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 “Governance Documents” section within the “Governance” 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.

The Company has an Insider Trading Policy governing the purchase, sale and other dispositions of the Company's securities that applies to the Company and its directors, officers and employees. The Company believes that its Insider Trading Policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and listing standards applicable to the Company. A copy of the Company's Insider Trading Policy is filed as Exhibit 19.1 to this Annual Report.

Item 11. Executive Compensation

The information required by this item is incorporated by reference to our Proxy Statement for the 2025 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2024.

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 2025 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2024.

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 2025 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2024.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2025 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2024.

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	Certificate of Amendment of the 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 May 23, 2024).
3.3	Certificate of Designations of Series A Junior Participating Preferred Stock 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 October 1, 2024).
3.4	Certificate of Elimination of Certificate of Designations of Series A Junior Participating Preferred Stock 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 December 17, 2024).
3.5	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, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee (9.000% Senior Notes). (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	First Supplemental Indenture, dated as of March 4, 2024, by and among Talos Production Inc., each of the guarantors party thereto and Wilmington Trust, National Association, as trustee and as collateral agent (9.000% Senior Notes) (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 5, 2024).
4.6	Indenture, dated as of February 7, 2024, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, (9.375% Senior 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 February 7, 2024).
4.7	First Supplemental Indenture, dated as of March 4, 2024, by and among Talos Production Inc., each of the guarantors party thereto and Wilmington Trust, National Association, as trustee and as collateral agent (9.375% Senior 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 March 5, 2024).
4.8	Form of 12.00% Second-Priority Senior Secured Note due 2026 (included as Exhibit A to Exhibit 4.1 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 January 8, 2021).
4.9	Form of 9.000% Second-Priority Senior Secured Note due 2029 (included as Exhibit A to Exhibit 4.5 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).
4.10	Form of 9.375% Second-Priority Senior Secured Note due 2031 (included as Exhibit A to Exhibit 4.6 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).
4.11	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).
4.12	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).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	Registration Rights Agreement, dated as of March 4, 2024, by and among Talos Energy Inc. and each of 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 March 5, 2024).

4.20	Rights Agreement, dated as of October 1, 2024, by and between Talos Energy Inc. and Computershare Trust Company, N.A. as Rights Agent (including the form of Certificate of Designations Series A Junior Participating Preferred Stock attached thereto as Exhibit A, the form of Right Certificate attached thereto as Exhibit B and the Summary of Rights to Purchase Preferred Shares attached thereto as Exhibit C (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 1, 2024).
4.21	First Amendment to Rights Agreement, dated December 17, 2024, by and between Talos Energy Inc. and Computershare Trust Company, N.A., as Rights 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 December 17, 2024).
4.22	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 (File No. 001-38497) 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 (File No. 001-38497) 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 (File No. 001-38497) 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 (File No. 001-38497) 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†	Amended and Restated Talos Energy Inc. 2021 Long Term Incentive 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 May 23, 2024).
10.12	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).
10.13†	Form of Indemnification Agreement (Directors and Officers) (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 29, 2024).
10.14†	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 (File No. 001-38497) filed with the SEC on August 9, 2018).
10.15†	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).

10.16† 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).

10.17† 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).

10.18† 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).

10.19† 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).

10.20† 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).

10.21† 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).

10.22† 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).

10.23† 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).

10.24† 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).

10.25† 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).

10.26 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 (File No. 001-38497) with the SEC on July 10, 2019).

10.27 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).

10.28 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).

10.29 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).

10.30	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).
10.31	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).
10.32	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).
10.33	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).
10.34	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 (incorporated by reference to Exhibit 10.33 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 29, 2024).
10.35	Borrowing Base Redetermination Agreement and Eleventh Amendment to Credit Agreement, dated December 4, 2024, by and among Talos Energy Inc., Talos Production Inc., each other Credit Party, JPMorgan Chase Bank, N.A., as Administrative Agent, and each Lender 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 5, 2024).
10.36#	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).
10.37†	Form of Separation and Release Agreement (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 7, 2024).
10.38†	Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement by and between Talos Energy Inc. and Joseph A. Mills, effective November 1, 2024 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on November 4, 2024).
10.39†	RSU Cancellation and Release Agreement by and between Talos Energy Inc. and Joseph A. Mills, effective November 1, 2024 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on November 4, 2024).
10.40†	Separation and Release Agreement by and between Talos Energy Inc. and Timothy S. Duncan, effective November 1, 2024 (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on November 4, 2024).
10.41†	Performance Share Unit Grant Notice and Performance Share Unit Agreement by and between Talos Energy Inc. and Timothy S. Duncan, effective November 1, 2024 (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on November 4, 2024).
10.42†	Stock Award Grant Notice and Stock Award Agreement by and between Talos Energy Inc. and Timothy S. Duncan, effective November 1, 2024 (incorporated by reference to Exhibit 10.5 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on November 4, 2024).

10.43	Cooperation Agreement, dated December 16, 2024, by and between Talos Energy Inc. and Control Empresarial de Capitales, S.A. de C.V. (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 17, 2024).
10.44†	Equity Interest Purchase Agreement, dated December 16, 2024, by and between Talos Production Inc. and Zamajal, S.A. de C.V. (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 17, 2024).
10.45†	Offer Letter Agreement, dated February 2, 2025, by and between Talos Energy Inc. and Paul Goodfellow, effective February 2, 2025 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 3, 2025).
10.46†	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 February 3, 2025).
10.47†	Form of Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (2024) (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 12, 2024).
10.48†	Form of Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (2024) (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on November 12, 2024).
10.49†	Form of Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives Retention) (2024) (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on November 12, 2024).
19.1*	Talos Energy Inc. Insider Trading Policy.
21.1*	List of Subsidiaries of Talos Energy Inc.
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 (incorporated by reference to Exhibit 97.1 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 29, 2024).
99.1*	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2024.
101.INS*	Inline XBRL Instance.
101.SCH*	Inline XBRL Taxonomy Extension Schema With Embedded Linkbase Documents.
104*	Cover Page Interactive Data File (Embedded within the Inline XBRL document and included in Exhibit 101).

*	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 26, 2025	By:	/s/ Sergio L. Maiworm, Jr.
			Sergio L. Maiworm, Jr. Interim Co-President, Chief Financial Officer and Executive Vice President

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints William S. Moss, III 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/ William S. Moss, III William S. Moss, III	Interim Chief Executive Officer (Principal Executive Officer)	February 26, 2025
/s/ Sergio L. Maiworm, Jr. Sergio L. Maiworm, Jr.	Chief Financial Officer (Principal Financial Officer, Authorized Signatory)	February 26, 2025
/s/ Gregory Babcock Gregory Babcock	Chief Accounting Officer (Principal Accounting Officer, Authorized Signatory)	February 26, 2025
/s/ Paula R. Glover Paula R. Glover	Director	February 26, 2025
/s/ Neal P. Goldman Neal P. Goldman	Director	February 26, 2025
/s/ John “Brad” Juneau John “Brad” Juneau	Director	February 26, 2025
/s/ Donald R. Kendall, Jr. Donald R. Kendall, Jr.	Director	February 26, 2025
/s/ Richard Sherrill Richard Sherrill	Director	February 26, 2025
/s/ Charles M. Sledge Charles M. Sledge	Director	February 26, 2025
/s/ Shandell Szabo Shandell Szabo	Director	February 26, 2025

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, 2024 and 2023, 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, 2024, and the related notes and financial statement schedule listed in the Index at 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, 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 26, 2025 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 Matters

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

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 independent petroleum engineers.

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 independent petroleum engineers in estimating proved oil and gas reserves. Estimating reserves also requires the selection and evaluation of inputs, including historical production, oil and gas price assumptions, operating and capital costs assumptions, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to prepare the proved oil and gas reserve estimates for all properties as of December 31, 2024.

Auditing the Company's DD&A expense calculation is complex because of the use of the work of independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the independent petroleum 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 used by the independent petroleum engineers for use in estimating proved oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent petroleum engineers responsible for the preparation of the reserve estimates. We tested the completeness and accuracy of the financial data used by the independent petroleum engineers in the estimation of proved oil and gas reserves by agreeing significant inputs to source documentation, 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 proved 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 independent petroleum engineers' reserve report.

Evaluation of the fair value measurement of oil and gas properties acquired in the QuarterNorth Energy Inc. business combination

Description of the Matter

As described in Note 3 to the consolidated financial statements, the Company executed a merger agreement to acquire QuarterNorth Energy Inc. for net consideration of approximately $1.6 billion. The transaction was accounted for as a business combination.

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 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 assumptions and production profiles of reserve estimates, reserve category risk adjustment factors and discount rate using a market-based weighted average cost of capital.

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 valuation 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.

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.

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, 2024.

	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. 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 26, 2025

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, 2024, 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, 2024, 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, 2024 and 2023, 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, 2024, and the related notes and financial statement schedule listed in the Index at Item 15(a) and our report dated February 26, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2025

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

	Year Ended December 31,	
	2024	**2023**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 108,172	$ 33,637
Accounts receivable:		
Trade, net	236,694	178,977
Joint interest, net	133,562	79,337
Other, net	34,002	19,296
Assets from price risk management activities	33,486	36,152
Prepaid assets	77,487	64,387
Other current assets	35,980	10,389
Total current assets	659,383	422,175
Property and equipment:		
Proved properties	9,784,832	7,906,295
Unproved properties, not subject to amortization	587,238	268,315
Other property and equipment	35,069	34,027
Total property and equipment	10,407,139	8,208,637
Accumulated depreciation, depletion and amortization	(5,191,865)	(4,168,328)
Total property and equipment, net	5,215,274	4,040,309
Other long-term assets:		
Restricted cash	106,260	102,362
Assets from price risk management activities	253	17,551
Equity method investments	111,269	146,049
Other well equipment	58,306	54,277
Notes receivable, net	17,748	16,207
Operating lease assets	11,294	11,418
Other assets	12,008	5,961
Total assets	$ 6,191,795	$ 4,816,309
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 117,055	$ 84,193
Accrued liabilities	326,913	227,690
Accrued royalties	77,672	55,051
Current portion of long-term debt	—	33,060
Current portion of asset retirement obligations	97,166	77,581
Liabilities from price risk management activities	6,474	7,305
Accrued interest payable	49,084	42,300
Current portion of operating lease liabilities	3,837	2,666
Other current liabilities	44,854	48,769
Total current liabilities	723,055	578,615
Long-term liabilities:		
Long-term debt	1,221,399	992,614
Asset retirement obligations	1,052,569	819,645
Liabilities from price risk management activities	3,537	795
Operating lease liabilities	15,489	18,211
Other long-term liabilities	416,041	251,278
Total liabilities	3,432,090	2,661,158
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Preferred stock; $0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of December 31, 2024 and 2023, respectively	—	—
Common stock; $0.01 par value; 270,000,000 shares authorized; 187,434,908 and 127,480,361 shares issued as of December 31, 2024 and 2023, respectively	1,874	1,275
Additional paid-in capital	3,274,626	2,549,097
Accumulated deficit	(424,110)	(347,717)
Treasury stock, at cost; 7,417,385 and 3,400,000 shares as of December 31, 2024 and 2023, respectively	(92,685)	(47,504)
Total stockholders' equity	2,759,705	2,155,151
Total liabilities and stockholders' equity	$ 6,191,795	$ 4,816,309

See accompanying notes.

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

	Year Ended December 31,		
	2024	2023	2022
Revenues:			
Oil	1,806,148	$ 1,357,732	$ 1,365,148
Natural gas	105,528	68,034	227,306
NGL	61,892	32,120	59,526
Total revenues	1,973,568	1,457,886	1,651,980
Operating expenses:			
Lease operating expense	566,041	389,621	308,092
Production taxes	1,377	2,451	3,488
Depreciation, depletion and amortization	1,023,558	663,534	414,630
Accretion expense	117,604	86,152	55,995
General and administrative expense	201,517	158,493	99,754
Other operating (income) expense	(109,454)	(52,155)	33,902
Total operating expenses	1,800,643	1,248,096	915,861
Operating income (expense)	172,925	209,790	736,119
Interest expense	(187,638)	(173,145)	(125,498)
Price risk management activities income (expense)	(1,458)	80,928	(272,191)
Equity method investment income (expense)	(10,289)	(3,209)	14,222
Other income (expense)	(44,930)	12,371	31,800
Net income (loss) before income taxes	(71,390)	126,735	384,452
Income tax benefit (expense)	(5,003)	60,597	(2,537)
Net income (loss)	$ (76,393)	$ 187,332	$ 381,915
Net income (loss) per common share:			
Basic	$ (0.44)	$ 1.56	$ 4.63
Diluted	$ (0.44)	$ 1.55	$ 4.56
Weighted average common shares outstanding:			
Basic	175,605	119,894	82,454
Diluted	175,605	120,752	83,683

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, 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
Equity-based compensation	—	—	21,987	—	—	—	21,987
Equity-based compensation tax withholdings	—	—	(6,206)	—	—	—	(6,206)
Equity-based compensation stock issuances	1,105,095	11	(11)	—	—	—	—
Issuance of common stock for acquisition (Note 3)	24,349,452	243	322,387	—	—	—	322,630
Issuance of common stock (Note 10)	34,500,000	345	387,372	—	—	—	387,717
Purchase of treasury stock	—	—	—	—	4,017,385	(45,181)	(45,181)
Net income (loss)	—	—	—	(76,393)	—	—	(76,393)
Balance at December 31, 2024	187,434,908	$ 1,874	$ 3,274,626	$ (424,110)	7,417,385	$ (92,685)	$ 2,759,705

See accompanying notes.

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

	Year Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income (loss)	$ (76,393)	$ 187,332	$ 381,915
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion, amortization and accretion expense	1,141,162	749,686	470,625
Amortization of deferred financing costs and original issue discount	9,303	15,039	14,379
Equity-based compensation expense	14,462	12,953	15,953
Price risk management activities (income) expense	1,458	(80,928)	272,191
Net cash received (paid) on settled derivative instruments	4,710	(9,457)	(425,559)
Equity method investment (income) expense	10,289	3,209	(14,222)
Loss (gain) on extinguishment of debt	60,256	—	1,569
Settlement of asset retirement obligations	(108,789)	(86,615)	(69,596)
Loss (gain) on sale of assets	38	(66,115)	303
Loss (gain) on sale of business	(100,482)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	8,576	20,352	14,927
Other current assets	(6,964)	7,066	(36,545)
Accounts payable	(3,831)	(60,401)	24,258
Other current liabilities	1,290	(96,960)	73,531
Other non-current assets and liabilities, net	7,508	(76,092)	(13,990)
Net cash provided by (used in) operating activities	962,593	519,069	709,739
Cash flows from investing activities:			
Exploration, development and other capital expenditures	(508,914)	(561,434)	(323,164)
Cash acquired in excess of payments for acquisitions	—	17,617	—
Payments for acquisitions, net of cash acquired	(936,214)	—	(3,500)
Proceeds from (cash paid for) sale of property and equipment, net	1,161	73,004	1,937
Contributions to equity method investees	(22,988)	(29,447)	(2,250)
Investment in intangible assets	—	(12,366)	—
Proceeds from sales of business	146,676	—	—
Proceeds from sale of equity method investment	—	—	15,000
Net cash provided by (used in) investing activities	(1,320,279)	(512,626)	(311,977)
Cash flows from financing activities:			
Issuance of common stock	387,717	—	—
Issuance of senior notes	1,250,000	—	—
Redemption of senior notes	(897,116)	(30,000)	(18,184)
Proceeds from Bank Credit Facility	880,000	825,000	85,000
Repayment of Bank Credit Facility	(1,080,000)	(625,000)	(460,000)
Deferred financing costs	(32,872)	(11,775)	(189)
Other deferred payments	(2,389)	(1,545)	—
Payments of finance lease	(17,834)	(16,306)	(25,493)
Purchase of treasury stock	(45,181)	(47,504)	—
Employee stock awards tax withholdings	(6,206)	(7,459)	(4,603)
Net cash provided by (used in) financing activities	436,119	85,411	(423,469)
Net increase (decrease) in cash, cash equivalents and restricted cash	78,433	91,854	(25,707)
Cash, cash equivalents and restricted cash:			
Balance, beginning of period	135,999	44,145	69,852
Balance, end of period	$ 214,432	$ 135,999	$ 44,145
Supplemental non-cash transactions:			
Capital expenditures included in accounts payable and accrued liabilities	$ 85,550	$ 114,972	$ 105,773
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 130,841	$ 130,313	$ 91,809

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, innovative, independent energy company focused on maximizing long-term value through our oil and gas exploration and production ("Upstream") business in the United States ("U.S.") Gulf of America and offshore Mexico. The Company leverages decades of technical and offshore operational expertise to acquire, explore, and produce assets in key geological trends while maintaining a focus on safe and efficient operations, environmental responsibility and community impact.

Basis of Presentation and Consolidation

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of the Parent Company and entities in which the Parent Company holds a controlling financial interest including any variable interest entity in which the Parent Company is the primary beneficiary. 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

From January 1, 2024 through March 18, 2024, the Company had two operating segments: (i) exploration and production of oil, natural gas and NGLs ("Upstream Segment") and (ii) CCS ("CCS Segment"). Both segments are reportable based on the Company's measure of segment profit or loss. The legal entities included in the CCS Segment were 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 16 — *Segment Information.*

Recently Adopted Accounting Standards

Segment Reporting — In November 2023, the Financial Accounting Standards Board ("FASB") issued an update to the required disclosures for segment reporting to improve reportable segment disclosures, primarily through enhanced disclosures about significant segment expenses that are included within segment profit and loss are required to be disclosed. The disclosure guidance became effective in 2024 for annual periods only; will become effective for interim periods during 2025; and was adopted on a retrospective basis for all prior periods presented in the financial statements. The enhanced segment disclosures are included in Note 16 — *Segment Information*. As of December 31, 2024, the Company has a single reportable segment entity managed on a consolidated basis. Upon adoption of the new disclosure guidance and a change in the chief operating decision maker ("CODM"), the Company's measure of segment profit or loss became net income (loss) because the segment reporting guidance requires disclosure of the measure used by the CODM that is closest to GAAP. Previously, the Company's measure of segment profit or loss was Adjusted EBITDA.

Recently Issued Accounting Standards Not Yet Adopted

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 tabular rate reconciliation will require both percentages and dollars. Currently, there is an option to present the table in either percentages or dollars. 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 continues to evaluate the impact of this new disclosure guidance.

Disaggregation of Income Statement Expenses — In November 2024, the FASB issued an update requiring the disaggregated disclosure of income statement expenses. The guidance does not change the expense captions an entity presents on the face of the income statement; rather, it requires disaggregation of certain expense captions into specified categories in disclosures within the footnotes to the financial statements. Such disclosures must be made on an annual and interim basis in a tabular format in the footnotes to the financial statements. Entities will be required to disaggregate any relevant expense caption presented on the face of the income statement within continuing operations into the following required natural expense categories, as applicable: (1) purchases of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, and (5) depreciation, depletion, and amortization recognized as part of oil- and gas-producing activities or other depletion expenses. The update is effective for fiscal years beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027 on a prospective retrospective basis. Early adoption and retrospective application are 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.

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, 2024 and 2023, the Company had allowances of $25.5 million and $8.8 million, respectively, presented net in "Accounts receivable" on the Consolidated Balance Sheets. See Note 3 — *Acquisitions and Divestitures* for further discussion on the allowances acquired as part of the QuarterNorth Acquisition.

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 cash flows from derivatives 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 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, advance payments to operators, 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 and external costs directly related to the acquisition of assets, 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.

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, 2024, 2023 and 2022.

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, 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. Certain of the Company's leases include one or more options to renew the lease, with renewal terms that can extend the lease term for additional years. When determining if renewals should be included in the lease term to be recognized, the Company utilizes the reasonably certain threshold, therefore, certain of the leases included in the calculation of its ROU assets and lease liabilities could include optional renewal periods for which it is not contractually obligated, but for which the Company currently expects to exercise such options.

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 when there is a balance outstanding and in "Other assets" on the Consolidated Balance Sheets when no such balance is outstanding.

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 and remove or appropriately abandon all production facilities, structures and pipelines following cessation of operations. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to plug, remove or abandon 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 15 — *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 11 — *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 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 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.

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 and PSUs. See Note 13 — *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 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 gas 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,		
	2024	2023	2022
Shell Trading (US) Company	48%	54%	44%
Exxon Mobil Corporation	17%	**	**
Valero Energy Corporation	**	21%	23%
Chevron Products Company	**	**	11%

** 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,	
	2024	2023
Cash and cash equivalents	$ 108,172	$ 33,637
Restricted cash included in Other long-term assets	106,260	102,362
Total cash, cash equivalent and restricted cash	$ 214,432	$ 135,999

Note 3 — Acquisitions and Divestitures

Acquisitions — 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.

QuarterNorth Acquisition — On March 4, 2024, the Company completed the acquisition of QuarterNorth Energy Inc. ("QuarterNorth"), a privately-held U.S. Gulf of America exploration and production company (the "QuarterNorth Acquisition," and the merger agreement related thereto, the "QuarterNorth Merger Agreement") for consideration consisting of (i) $1,247.4 million in cash and (ii) 24.3 million shares of the Company's common stock valued at $322.6 million. The cash payment was partially funded with a January 2024 underwritten public offering of 34.5 million shares of the Company's common stock (See Note 10 — *Stockholders' Equity*), borrowings under the Bank Credit Facility and the Senior Notes (as defined in Note 8 — *Debt*).

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

Shares of Talos common stock	24,349,452
Talos common stock price(1)	$ 13.25
Common stock value	$ 322,630
Cash consideration	$ 1,247,419
Total purchase price(2)	$ 1,570,049

(1) Represents the closing price of the Company's common stock on March 4, 2024, the date of the closing of the QuarterNorth Acquisition.

(2) Total purchase price net of $331.4 million cash and cash equivalents acquired at closing is $1,238.7 million.

The following table presents the final allocation of the purchase price to the assets acquired and liabilities assumed, based on their fair values on March 4, 2024 (in thousands):

Cash and cash equivalents	$	331,374
Other current assets[(1)]		165,696
Property and equipment		1,622,414
Other long-term assets		20,781
Current liabilities:		
Current portion of asset retirement obligations		(6,748)
Other current liabilities		(199,704)
Long-term liabilities:		
Asset retirement obligations		(192,771)
Deferred tax liabilities		(168,102)
Other long-term liabilities		(2,891)
Allocated purchase price	$	1,570,049

(1) Included in current assets is acquired receivables in the amount of $136.3 million excluding receivables with credit deterioration, which represents the contractual value net of allowances of approximately $15.5 million.

The fair values determined for accounts receivable, accounts payable and other current assets and most current liabilities were generally equivalent to the carrying value due to their short-term nature.

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, development and plugging and abandonment 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 and probable 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 NYMEX forward strip prices, escalated for inflation, 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 fair values of derivative instruments were estimated using a third-party industry standard pricing model which considers various inputs such as quoted forward commodity prices, discount rates, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant data.

The Company incurred approximately $21.6 million of acquisition-related costs in connection with the QuarterNorth Acquisition exclusive of severance expense, of which $18.6 million was recognized during the year ended December 31, 2024 and $3.0 million was recognized for the year ended December 31, 2023. These costs were reflected in “General and administrative expense” on the Consolidated Statements of Operations except for $4.9 million of fees associated with an unutilized bridge loan that was included in “Interest expense” on the Consolidated Statements of Operations during the year ended December 31, 2024. Additionally, the Company incurred $22.2 million in severance expense in connection with the QuarterNorth Acquisition for the year ended December 31, 2024. See Note 11 — *Employee Benefits Plans and Share-Based Compensation* for additional discussion.

The following table presents revenue and net income attributable to the QuarterNorth Acquisition for the period from March 4, 2024 to December 31, 2024:

Revenue	$	503,397
Net income (loss)	$	89,209

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, 2024 and 2023 as if the QuarterNorth Acquisition had occurred on January 1, 2023. The unaudited pro forma information was derived from historical statements of operations of the Company and QuarterNorth 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 Senior Notes, (iii) general and administrative expense adjusted for transaction related costs incurred (including severance), (iv) weighted average basic and diluted shares of common stock outstanding from the issuance of 24.3 million shares of common stock as partial consideration for the QuarterNorth Acquisition and (v) weighted average basic and diluted shares of common stock outstanding from the issuance of 34.5 million shares of common stock from the underwritten public offering in January 2024 that partially funded the cash portion of the QuarterNorth Acquisition. Supplemental pro forma earnings for the year ended December 31, 2023 were adjusted to include $31.7 million of general and administrative expenses and supplemental pro forma earnings for the year ended December 31, 2024 were adjusted to exclude these expenses. This information does not purport to be indicative of results of operations that would have occurred had the QuarterNorth Acquisition occurred on January 1, 2023, nor is such information indicative of any expected future results of operations (in thousands, except for the per share data).

	Year Ended December 31,	
	2024	2023
Revenue	$ 2,100,837	$ 2,141,579
Net income (loss)	$ (69,131)	$ 245,720
Basic net income (loss) per common share	$ (0.38)	$ 1.37
Diluted net income (loss) per common share	$ (0.38)	$ 1.37

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 America (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 NYMEX forward strip prices, escalated for inflation, 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 11 — *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):

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, and supplemental pro forma earnings for the year ended December 31, 2023 were adjusted to exclude these 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

Asset Acquisition

Acquisitions accounted for as asset acquisitions require, among other items, the cost of the acquisition to be allocated to the assets acquired and liabilities assumed based on relative fair value basis.

Acquisition of Working Interests in Monument Oil Discovery — The Company executed two separate definitive agreements to acquire a collective 21.4% non-operated working interest in the Monument oil discovery ("Monument Project") in the Deepwater U.S. Gulf of America located on certain Walker Ridge lease blocks. Cash consideration totaling $20.2 million, after customary closing adjustments, was paid on the closing dates of July 31, 2024 and August 2, 2024. An additional aggregate $24.4 million will be paid periodically in installments beginning January 1, 2025 through April 1, 2026. The Company allocated $42.6 million to proved properties. Deferred payments have been included in "Other current liabilities" and "Other long-term liabilities" on the Consolidated Balance Sheets at December 31, 2024 based on timing of the scheduled payment. The Monument Project will initially be developed with two subsea wells tied back to a third-party floating production system.

Subsequent Event — On February 20, 2025, the Company executed a definitive agreement to acquire an additional 8.3% non-operated working interest in the Monument Project for $6.3 million, excluding customary effective date adjustments. An additional aggregate $6.3 million will be paid after certain milestones are achieved. The Company expects to close the transaction in March 2025.

Divestitures

Talos Low Carbon Solutions Divestiture — On March 18, 2024, the Company entered into a definitive agreement relating to and subsequently completed the sale of its wholly owned subsidiary, Talos Low Carbon Solutions LLC to TotalEnergies E&P USA, Inc. for an initial purchase price of $125.0 million plus customary reimbursements and adjustments, combined totaling approximately $142.0 million (the "TLCS Divestiture"). The TLCS Divestiture includes the Company's entire CCS business including its equity investments in three projects along the U.S. Gulf Coast: Bayou Bend CCS LLC, Harvest Bend CCS LLC, and Coastal Bend CCS LLC. The TLCS Divestiture also entitles Talos to certain contingent payments, of which $4.7 million was received during the year ended December 31, 2024 and $12.5 million is expected to be received during the year ended December 31, 2025. A gain of $100.4 million was recognized related to TLCS Divestiture during the year ended December 31, 2024. The gain on the TLCS Divestiture is presented as "Other operating income (expense)" on the Consolidated Statements of Operations and the contingent payments are included in "Other current assets" on the Consolidated Balance Sheets at December 31, 2024 based on timing of the expected receipt.

The Company incurred approximately $6.1 million of costs in connection with the TLCS Divestiture exclusive of severance expense, of which $5.5 million was recognized during the year ended December 31, 2024 and reflected in "General and administrative expense" on the Consolidated Statements of Operations. Additionally, the Company incurred $3.7 million in severance expense in connection with the TLCS Divestiture for the year ended December 31, 2024. See Note 11 — *Employee Benefits Plans and Share-Based Compensation* for additional discussion.

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. ("Zamajal"), a subsidiary of Grupo Carso, S.A.B. de C.V. ("Carso") for $74.9 million in cash consideration with an additional $49.9 million contingent on first oil production from the Zama Field (the "2023 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, currently holds a 17.4% unitized interest in the Zama Field.

As a result of the 2023 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 2023 Mexico Divestiture, which was an orderly transaction between market participants. A gain of $66.2 million was recognized on the 2023 Mexico Divestiture during the year ended December 31, 2023 which is included in "Other operating (income) expense" on the Consolidated Statements of Operations.

On December 16, 2024, the Company entered into an agreement to sell an additional equity interest in Talos Mexico to Zamajal. See Note 7 — *Equity Method Investments* for additional information.

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 America deep and shallow waters. During 2024, 2023 and 2022, 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, 2024, its ceiling test computation was based on SEC pricing of $75.51 per Bbl of oil, $2.45 per Mcf of natural gas and $21.91 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 America federal lease sales, certain geological and geophysical costs, expenditures associated with certain exploratory wells in progress and capitalized interest.

The following table sets forth a summary of the Company's oil and natural gas property costs not being amortized at December 31, 2024, by the year in which such costs were incurred (in thousands):

		Year Ended December 31,			
	Total	2024	2023	2022	2021 and Prior
Acquisition United States	$ 540,735	$ 347,661	$ 185,437	$ —	$ 7,637
Exploration United States	46,503	31,592	8,961	3,097	2,853
Total unproved properties, not subject to amortization	$ 587,238	$ 379,253	$ 194,398	$ 3,097	$ 10,490

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 seven 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. Costs associated with the Company's leases are either expensed or capitalized depending on how the underlying asset is utilized. 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.

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,		
	2024	2023	2022
Finance lease costs - interest on lease liabilities	$ 12,948	$ 14,476	$ 7,558
Operating lease costs, excluding short-term leases(1)	4,207	4,883	2,281
Short-term lease costs(2)	100,895	117,132	55,072
Variable lease costs(3)	2,464	2,888	1,450
Variable and fixed sublease income	(1,436)	(482)	—
Total lease costs	$ 119,078	$ 138,897	$ 66,361

(1) Operating lease costs 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 and well intervention vessels, 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,	
	2024	2023
Operating leases:		
Operating lease assets	$ 11,294	$ 11,418
Current portion of operating lease liabilities	$ 3,837	$ 2,666
Operating lease liabilities	15,489	18,211
Total operating lease liabilities	$ 19,326	$ 20,877
Finance leases:		
Proved properties	$ 166,261	$ 166,261
Other current liabilities	$ 19,589	$ 17,834
Other long-term liabilities	111,641	131,230
Total finance lease liabilities	$ 131,230	$ 149,064

The table below presents the lease maturity by year as of December 31, 2024 (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
2025	$ 5,656	$ 30,782
2026	4,983	30,782
2027	4,753	30,782
2028	4,610	30,782
2029	3,226	30,782
Thereafter	1,357	12,825
Total lease payments	$ 24,585	$ 166,735
Imputed interest	(5,259)	(35,505)
Total lease liabilities	$ 19,326	$ 131,230

The table below presents the weighted average remaining lease term and discount rate related to leases:

	Year Ended December 31,		
	2024	2023	2022
Weighted average remaining lease term:			
Operating leases	4.8 years	5.9 years	6.4 years
Finance leases	5.4 years	6.4 years	7.4 years
Weighted average discount rate:			
Operating leases	10.7%	10.8%	11.8%
Finance leases	9.2%	9.2%	9.2%

The table below presents the supplemental cash flow information related to leases (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Operating cash outflow from finance leases	$ 12,948	$ 14,476	$ 7,181
Operating cash outflow from operating leases	$ 5,634	$ 6,318	$ 3,722
ROU assets obtained in exchange for new finance lease liabilities	$ —	$ —	$ 166,261
ROU assets obtained in exchange for new operating lease liabilities(1)	$ 1,909	$ 12,971	$ 474
Remeasurement of lease liability arising from modification of ROU asset(2)	$ —	$ (5,124)	$ —

(1) See QuarterNorth Acquisition and EnVen Acquisition each 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, 2024 and 2023, 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, 2024		December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
9.000% Second-Priority Senior Secured Notes – due February 2029	$ 611,135	$ 640,619	$ —	$ —
9.375% Second-Priority Senior Secured Notes – due February 2031	$ 610,264	$ 635,750	$ —	$ —
12.00% Second-Priority Senior Secured Notes – due January 2026	$ —	$ —	$ 601,353	$ 655,130
11.75% Senior Secured Second Lien Notes – due April 2026	$ —	$ —	$ 234,221	$ 233,410
Bank Credit Facility – matures March 2027	$ —	$ —	$ 190,100	$ 200,000

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 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.

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,		
	2024	2023	2022
Net cash received (paid) on settled derivative instruments	$ 4,710	$ (9,457)	$ (425,559)
Unrealized gain (loss)	(6,168)	90,385	153,368
Price risk management activities income (expense)	$ (1,458)	$ 80,928	$ (272,191)

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, 2024:

Swap Contracts

Production Period	Settlement Index	Volumes	Swap Price
Crude oil:		*(Bbls)*	*(per Bbl)*
January 2025 – December 2025	NYMEX WTI CMA	25,951	$ 72.66
January 2026 – June 2026	NYMEX WTI CMA	10,497	$ 65.98
Natural gas:		*(MMBtu)*	*(per MMBtu)*
January 2025 – December 2025	NYMEX Henry Hub	57,384	$ 3.50
January 2026 – December 2026	NYMEX Henry Hub	20,000	$ 3.65

Two-Way Collar Contracts

Production Period	Settlement Index	Volumes	Floor Price	Ceiling Price
Crude oil:		*(Bbls)*	*(per Bbl)*	*(per Bbl)*
January 2025 – March 2025	NYMEX WTI CMA	3,000	$ 65.00	$ 84.35

The following tables provide additional information related to financial instruments measured at fair value on a recurring basis (in thousands):

	December 31, 2024			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas derivatives	$ —	$ 33,739	$ —	$ 33,739
Liabilities:				
Oil and natural gas derivatives	—	(10,011)	—	(10,011)
Total net asset (liability)	$ —	$ 23,728	$ —	$ 23,728

	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

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, 2024		December 31, 2023	
	Assets	Liabilities	Assets	Liabilities
Oil and natural gas derivatives:				
Current	$ 33,486	$ 6,474	$ 36,152	$ 7,305
Non-current	253	3,537	17,551	795
Total gross amounts presented on balance sheet	33,739	10,011	53,703	8,100
Less: Gross amounts not offset on the balance sheet	10,011	10,011	8,100	8,100
Net amounts	$ 23,728	$ —	$ 45,603	$ —

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, 2024 represent derivative instruments from seven 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 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, 2024 would have been $23.7 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	Year Ended December 31,	
	December 31, 2024	2024	2023
Upstream:			
Talos Mexico	50.1%	$ 110,194	$ 107,259
SP 49 Pipeline LLC	33.3%	1,075	861
CCS[1]:			
Bayou Bend CCS LLC	— %	—	28,183
Harvest Bend CCS LLC	— %	—	9,746
Coastal Bend CCS LLC	— %	—	—
Total Equity Method Investments		$ 111,269	$ 146,049

(1) See TLCS Divestiture discussion in Note 3 — *Acquisitions and Divestitures*.

Talos Mexico

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.

On December 16, 2024, the Company entered into an agreement to sell an additional 30.1% equity interest in Talos Mexico to Zamajal, a subsidiary of Carso, for $49.7 million in cash consideration with an additional $33.1 million contingent on first oil production from the Zama Field (the "Incremental Mexico Equity Sale"). The Incremental Mexico Equity Sale is expected to close during 2025 upon the satisfaction of customary closing conditions and the receipt of all regulatory approvals. After consummation of the Incremental Mexico Equity Sale, Talos Mexico, which currently holds a 17.4% interest in the Zama field, will be owned 20.0% by the Company and 80.0% by Zamajal. While the Company anticipates the Incremental Mexico Equity Sale will close in 2025, there can be no assurance that all of the conditions to closing, including obtaining necessary regulatory approvals, will be satisfied. See Note 14 — *Related Party Transactions* for additional information on Carso.

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"). 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. In March 2024, the Company sold its entire CCS business inclusive of Bayou Bend. See Note 3 – *Acquisitions and Divestitures* for additional information on the TLCS Divestiture.

VIE Disclosures

VIE and Primary Beneficiary Determination — Talos Mexico was determined to be a VIE. Talos Mexico did not have sufficient equity at risk to finance activities without additional subordinated financial support. The Company is not the primary beneficiary of Talos Mexico due to the governance structure of this entity. The most significant activities of Talos Mexico are jointly controlled by the owners.

Financings — Talos Mexico has historically been funded through equity contributions from owners.

Maximum Exposure — The Company's maximum exposure to loss as result of its involvement with Talos Mexico is the carrying amount of its 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.

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):

	December 31, 2024	December 31, 2023
9.000% Second-Priority Senior Secured Notes – due February 2029	$ 625,000	$ —
9.375% Second-Priority Senior Secured Notes – due February 2031	625,000	—
12.00% Second-Priority Senior Secured Notes – due January 2026	—	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	1,250,000	1,066,041
Unamortized discount, premium and deferred financing cost, net	(28,601)	(40,367)
Total debt	1,221,399	1,025,674
Less: Current portion of long-term debt	—	33,060
Long-term debt	$ 1,221,399	$ 992,614

9.000% Second-Priority Senior Secured Notes—due February 2029

The 9.000% Second-Priority Senior Secured Notes due 2029 (the "9.000% Notes") were issued pursuant to an indenture dated February 7, 2024, by and among the Company, Talos Production Inc. (the "Issuer"), the subsidiary guarantors party thereto (together with the Company, the "Guarantors") and Wilmington Trust, National Association, as trustee and collateral agent. 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 rank equally in right of payment with all of the Issuer's and the Guarantors' existing and future senior obligations, are senior in right of payment to any obligations of the Issuer and the Guarantors future debt that is, by its term, expressly subordinated in right of payment to the 9.000% Notes and, to the extent of the value of the collateral, are effectively senior to all existing and future unsecured obligations of the Issuer and the Guarantors (other than the Company) and any future obligations of the Issuer and the Guarantors that are secured by the collateral on a junior-priority basis. The 9.000% Notes are effectively pari passu with all of the Issuer's and the Guarantors' existing and future obligations that are secured by the collateral on a second-priority basis including the 9.375% Notes (as defined below) and are effectively junior to any existing and future obligations of the Issuer and the Guarantors that are secured by the collateral on a senior-priority basis to the 9.000% Notes including indebtedness under the Bank Credit Facility. The 9.000% Notes mature on February 1, 2029 and have interest payable semi-annually each February 1 and August 1, commencing August 1, 2024.

At any time prior to February 1, 2026, the Company may redeem up to 40% of the principal amount of the 9.000% Notes at a redemption rate of 109.00% of the principal amount plus accrued and unpaid interest. At any time prior to February 1, 2026, the Company may also redeem some or all of the 9.000% Notes, plus a "make-whole premium," together with accrued and unpaid interest, if any, to, but excluding, the date of redemption. Thereafter, the Company may redeem all or a portion of the 9.000% Notes in whole at any time or in part from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest if redeemed during the period commencing on February 1 of the years set forth below:

Period	Redemption Price
2026	104.500%
2027	102.250%
2028 and thereafter	100.000%

As of December 31, 2024, the Company has incurred debt issuance costs of $16.3 million related to the 9.000% Notes issued as part of the debt offering that partially funded the cash portion of the QuarterNorth Acquisition. The debt issue costs reduced the proceeds from the debt issued. See Note 3 — *Acquisitions and Divestitures* for further discussion on the QuarterNorth Acquisition.

9.375% Second-Priority Senior Secured Notes—due February 2031

The 9.375% Second-Priority Senior Secured Notes due 2031 (the "9.375% Notes" and, together with the 9.000% Notes, the "Senior Notes") were issued pursuant to an indenture dated February 7, 2024, by and among the Company, the Issuer, the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. 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 rank equally in right of payment with all of the Issuer's and the Guarantors' existing and future senior obligations, are senior in right of payment to any obligations of the Issuer and the Guarantors future debt that is, by its term, expressly subordinated in right of payment to the 9.375% Notes and, to the extent of the value of the collateral, are effectively senior to all existing and future unsecured obligations of the Issuer and the Guarantors (other than the Company) and any future obligations of the Issuer and the Guarantors that are secured by the collateral on a junior-priority basis. The 9.375% Notes are effectively pari passu with all of the Issuer's and the Guarantors' existing and future obligations that are secured by the collateral on a second-priority basis including the 9.000% Notes and are effectively junior to any existing and future obligations of the Issuer and the Guarantors that are secured by the collateral on a senior-priority basis to the 9.375% Notes including indebtedness under the Bank Credit Facility. The 9.375% Notes mature on February 1, 2031 and have interest payable semi-annually each February 1 and August 1, commencing August 1, 2024.

At any time prior to February 1, 2027, the Company may redeem up to 40% of the principal amount of the 9.375% Notes at a redemption rate of 109.375% of the principal amount plus accrued and unpaid interest. At any time prior to February 1, 2027, the Company may also redeem some or all of the 9.375% Notes, plus a "make-whole premium," together with accrued and unpaid interest, if any, to, but excluding, the date of redemption. Thereafter, the Company may redeem all or a portion of the 9.375% Notes in whole at any time or in part from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest if redeemed during the period commencing on February 1 of the years set forth below:

Period	Redemption Price
2027	104.688%
2028	102.344%
2029 and thereafter	100.000%

As of December 31, 2024, the Company has incurred debt issuance costs of $16.3 million related to the 9.375% Notes issued as part of the debt offering that partially funded the cash portion of the QuarterNorth Acquisition. The debt issue costs reduced the proceeds from the debt issued.

Debt Covenants for 9.000% Notes and 9.375% Notes

Each of the indentures that govern the 9.000% Notes and the 9.375% Notes contain covenants that, among other things, limit the Issuer's ability and the ability of its restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue certain convertible or redeemable equity securities; (ii) create liens to secure indebtedness; (iii) pay distributions or dividends on equity interests, redeem or repurchase equity securities or redeem junior lien, unsecured or subordinated indebtedness; (iv) make investments; (v) restrict distributions, loans or other asset transfers from the Issuer's restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of the Issuer's properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. These covenants are subject to certain exceptions and qualifications. The Company was in compliance with all debt covenants at December 31, 2024.

12.00% Second-Priority Senior Secured Notes

On February 7, 2024, the Company redeemed $638.5 million aggregate principal amount of the 12.00% Second-Priority Senior Secured Notes due 2026 (the "12.00% Notes") at 103.000% plus accrued and unpaid interest using the proceeds from the issuance of the Senior Notes. The debt redemption resulted in a loss on extinguishment of debt of $54.9 million, which is presented as "Other income (expense)" on the Consolidated Statements of Operations.

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.

11.75% Senior Secured Second Lien Notes

On February 7, 2024, the Company redeemed $227.5 million aggregate principal amount of the 11.75% Senior Secured Second Lien Notes due 2026 (the "11.75% Notes") at 102.938% plus accrued and unpaid interest using the proceeds from the issuance of the Senior Notes. The debt redemption resulted in a loss on extinguishment of debt of $5.4 million, which is presented as "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 the Bank Credit Facility with a syndicate of financial institutions. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter of each year based on a proved reserves report that the Company delivers to the administrative agent of its Bank Credit Facility.

On December 4, 2024, the Company entered into the Borrowing Base Redetermination Agreement and Eleventh Amendment to Credit Agreement (the “Eleventh Amendment”), in order to (i) decrease the borrowing base to $925.0 million and decrease the total commitments to $925.0 million and (ii) implement an availability cap such that, if the aggregate exposure of all lenders under the Bank Credit Facility would equal or exceed $800 million at any time after the date of the Eleventh Amendment, lenders holding at least two-thirds of the aggregate commitments shall approve the making of any addition loan or issuance of any additional letter of credit.

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, 2024, the Company's borrowing base was $925.0 million with total commitments of $925.0 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, 2024. See Note 15 — *Commitments and Contingencies* for the amount of letters of credit issued under the Bank Credit Facility as of December 31, 2024.

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, 2024 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, each of the indentures governing the Senior Notes restrict the Issuer and its restricted 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 indentures. 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 at least 2.25 to 1.00, (iii) immediately after giving effect to such transaction on a pro forma basis, the consolidated leverage 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.

At December 31, 2024, restricted net assets of the Company's consolidated subsidiaries exceeded 25%.

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,	
	2024	2023
Balance, beginning of period	$ 897,226	$ 541,661
Obligations assumed[1]	199,519	258,858
Obligations incurred	107	14,199
Obligations settled	(108,789)	(86,615)
Obligations divested	—	(19,448)
Accretion expense	117,604	86,152
Changes in estimate[2]	44,068	102,419
Balance, end of period	$ 1,149,735	$ 897,226
Less: Current portion	97,166	77,581
Long-term portion	$ 1,052,569	$ 819,645

(1) Assumed in connection with the QuarterNorth Acquisition and EnVen Acquisition. See further discussion in Note 3 — *Acquisitions and Divestitures*.
(2) Changes in estimate were primarily due to changes in expected timing and increases in cost estimates to satisfy certain future abandonment obligations.

At December 31, 2024, the Company has (1) restricted cash of $106.3 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 — Stockholders' Equity

Underwritten Equity Offering

On January 22, 2024, we closed an underwritten public offering of 34.5 million shares of our common stock, which generated net proceeds of $387.7 million after deducting underwriting discounts of $15.1 million and offering expenses of $0.8 million.

Stockholder Rights Agreement

On October 1, 2024, the Company entered into a Rights Agreement (the "Rights Agreement") with Computershare Trust Company, N.A., as rights agent (the "Rights Agent"). In connection therewith, the Board of Directors of the Company (the "Board") declared a dividend of one preferred share purchase right ("Right") for each outstanding share of the Company's common stock, par value $0.01 per share (the "Common Stock"). The dividend became payable on October 11, 2024 to stockholders of record as of the close of business on such date.

On December 17, 2024, the Company and the Rights Agent entered into the First Amendment to the Rights Agreement (the "Amendment"). The Amendment accelerated the expiration of the Rights from the close of business on October 1, 2025 to the close of business on December 17, 2024. Accordingly, the Rights issued under the Rights Agreement expired and are no longer outstanding. Because the Rights have expired as a result of the Amendment, no preferred shares will be issued pursuant to the Rights Agreement or the Rights.

Note 11 — Employee Benefits Plans and Share-Based Compensation

Severance

The following table summarizes severance accrual activity in connection with the EnVen Acquisition, QuarterNorth Acquisition and TLCS Divestiture included in "Other current liabilities" and "Other long-term liabilities" on the Consolidated Balance Sheets, and the changes in that liability were as follows (in thousands):

	Year Ended December 31,	
	2024	2023
Balance, beginning of period	$ 6,294	$ —
Accrual additions	25,991	25,348
Benefit payments	(31,451)	(19,054)
Balance, end of period	834	6,294
Less: Current portion	827	6,190
Long-term portion	$ 7	$ 104

The above table includes involuntary termination benefits that are being provided pursuant to a one-time benefit arrangement that is being recognized 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 employment agreements. Severance costs are reflected in "General and administrative expense" on the Consolidated Statements of Operations.

In connection with the departure of the Company's former President and Chief Executive Officer on August 29, 2024, the Company incurred $5.0 million of severance, all of which is reflected in "General and administrative expense" on the Consolidated Statements of Operations.

Long Term Incentive Plan

The Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan (the "A&R LTIP") became effective on May 23, 2024 and authorizes the Company to grant awards of up to 12,439,415 shares of the Company's common stock, subject to the share recycling and adjustment provisions of the A&R LTIP. The A&R LTIP also extends the term of the plan to May 23, 2034.

The A&R 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 other service providers of the Company and its affiliates are eligible to receive awards under the A&R LTIP.

Award of Vested Stock — On November 1, 2024, the Company entered into a separation and release agreement with its former President and Chief Executive Officer and granted, pursuant to the A&R LTIP, a stock award of 28,519 fully vested shares of the Company's common stock. This grant represented the pro rata portion of the Company's 2024 LTIP award to which the former executive was entitled.

Restricted Stock Units – Employees **—** RSUs granted to employees under the A&R LTIP 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, 2024 was approximately $31.7 million, which is expected to be recognized over a weighted average period of 2.2 years.

On September 9, 2024, there were 157,071 RSUs issued as retention awards to executive officers that are required to report their beneficial ownership of the Company's equity securities and any transactions in such securities. These retention RSUs will vest ratably on each of September 9, 2025, September 9, 2026, and September 9, 2027.

On November 1, 2024, the Company's former Interim Chief Executive Officer and President was granted 43,630 RSUs, all of which vested on December 31, 2024. The Company's former Interim Chief Executive Officer and President also agreed to forfeit 4,273 RSUs that he was granted in 2024 for his service as a non-employee member of the Board.

Restricted Stock Units – Non-employee Directors — RSUs granted to non-employee directors under the A&R LTIP vest approximately one year following the date of grant, subject to such non-employee director's continued service through the vesting date. Each non-employee director is provided the opportunity to defer the settlement of their RSUs until a later date, as timely selected pursuant to a deferral election form. Following the vesting date, or such later date as elected by the director pursuant to the deferral election, these RSUs are settled 60% in shares of our common stock and 40% in cash, unless the director timely elects for the awards to be settled 100% in shares of our common stock.

The following table summarizes RSU activity:

	Restricted Stock Units		Weighted Average Grant Date Fair Value
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	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
Granted	3,155,776	$	11.97
Vested	(1,534,798)	$	13.72
Forfeited	(384,904)	$	14.65
Unvested RSUs at December 31, 2024(1)	3,542,435	$	12.83

(1) As of December 31, 2024 and 2023, 35,508 and 26,975, respectively, of the unvested RSUs were accounted for as liability awards in "Accrued liabilities" on the Consolidated Balance Sheet.

Performance Share Units – Employees — PSUs granted to employees under the A&R LTIP represent the contingent right to receive one share of common stock. However, the number of shares of common stock issuable 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, 2024 was approximately $3.4 million, which is expected to be recognized over a weighted average period of 1.8 years.

The following table summarizes PSU activity:

	Performance Share Units	Weighted Average Grant Date Fair Value
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
Granted[(4)]	299,472	$ 11.36
Forfeited[(5)]	(666,455)	$ 22.71
Unvested PSUs at December 31, 2024	649,666	$ 15.27

(1) There were 314,833 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 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 were added back to the plan reserve for future grants under the recycling provisions of the A&R 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.

(4) Eligible to vest based on continued employment and the relative annualized TSR of the Company as compared to a peer group over a three-year performance period, as modified by the Company's absolute annualized TSR over the same performance period. Additionally, on November 1, 2024, the Company entered into a separation and release agreement with its former President and Chief Executive Officer and granted, pursuant to the A&R LTIP, an award of 38,844 PSUs. This grant represented the pro rata portion of the Company's 2024 LTIP award to which the former executive was entitled.

(5) The performance period for 475,604 PSUs ended on December 31, 2024. 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 2025. Since these awards were legally forfeited they were added back to the plan reserve for future grants under the recycling provisions of the A&R 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 at the date indicated:

	2024		2023			2022	
	Grant	Grant	Grant	Grant	Grant	Grant	Grant
	November 1	September 9	December 1	July 1	March 5	September 20	March 5
Expected term (in years)	2.2	2.3	2.1	2.5	2.8	2.3	2.8
Expected volatility	49.5 %	54.4 %	61.9 %	66.2 %	73.1 %	74.3 %	82.2 %
Risk-free interest rate	4.1 %	3.6 %	4.4 %	4.6 %	4.5 %	3.9 %	1.6 %
Dividend yield	— %	— %	— %	— %	— %	— %	— %
Fair value (in thousands)	$ 355	$ 3,047	$ 12	$ 173	$ 6,165	$ 621	$ 8,668

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 vested 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 were accounted for as a modification. The incremental cost of $9.7 million was recognized prospectively over the modified requisite service period. Additionally, the remaining unrecognized grant or modification date fair value of the original PSUs was 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,		
	2024	2023	2022
Share-based compensation costs	$ 22,088	$ 25,236	$ 28,280
Less: Amounts capitalized to oil and gas properties	7,626	12,283	12,327
Total share-based compensation expense	$ 14,462	$ 12,953	$ 15,953

Note 12 — Income Taxes

Income Tax Expense (Benefit)

The components of income tax expense (benefit) were as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Current income tax expense (benefit):			
Federal	$ (2,180)	$ 18	$ 1,334
State	103	58	41
Mexico	309	31	432
Total current income tax expense (benefit)	$ (1,768)	$ 107	$ 1,807
Deferred income tax expense (benefit):			
Federal	$ (10,874)	$ (61,182)	$ 567
State	17,645	478	92
Mexico	—	—	71
Total deferred income tax expense (benefit)	$ 6,771	$ (60,704)	$ 730
Total income tax expense (benefit)	$ 5,003	$ (60,597)	$ 2,537

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,		
	2024	2023	2022
Income tax expense (benefit) at the federal statutory tax rate	$ (14,992)	$ 26,614	$ 80,735
State income taxes	(200)	1,748	1,591
Impact of foreign operations	852	13,539	15,657
Effect of change in state rate	38,199	—	—
Prior year taxes	(2,937)	1,184	(2,920)
Change in valuation allowance	(20,273)	(106,815)	(96,537)
Other permanent differences	4,354	3,133	4,011
Total income tax expense (benefit)	$ 5,003	$ (60,597)	$ 2,537
Effective tax rate	(7.01)%	(47.81)%	0.66 %

The Company's effective tax rate for the year ended December 31, 2024 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax expense of $38.2 million related to the effect of a change in state tax rate and $4.3 million related to permanent differences, offset with a non-cash tax benefit of $20.3 million related to the partial release of the valuation allowance for certain of its state deferred tax assets.

The Company's effective tax rate for the years 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 federal 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 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 and 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. Net deferred tax assets and liabilities is included in “Other liabilities” on the Consolidated Balance Sheets as of December 31, 2024. Significant components of deferred tax assets and liabilities were as follows (in thousands):

	Year Ended December 31,	
	2024	**2023**
Deferred tax assets:		
Federal net operating loss	$ 108,717	$ 147,252
Foreign tax loss carryforward	452	509
State net operating loss	12,426	24,840
Tax credits	—	107
Interest expense carryforward	74,957	46,414
Asset retirement obligations	262,773	190,248
Other well equipment	9,796	1,317
Accrued bonus	9,040	5,050
Share-based compensation	5,343	5,172
Operating lease liabilities	4,340	4,427
Finance lease liabilities	29,926	31,607
Other	5,764	3,383
Total deferred tax assets	523,534	460,326
Valuation allowance	(3,325)	(23,697)
Total deferred tax assets, net	$ 520,209	$ 436,629
Deferred tax liabilities:		
Oil and gas properties	$ 772,439	$ 512,918
Operating lease assets	2,508	2,421
Derivatives	5,411	9,670
Prepaid	6,428	3,847
Total deferred tax liabilities	786,786	528,856
Net deferred tax liability	$ (266,577)	$ (92,227)

Net Operating Loss

The table below presents the details of the Company’s net operating loss carryovers as of December 31, 2024 (in thousands):

	Amount	Expiration Year
Federal net operating losses	$ 222,354	2036 - 2037
Federal net operating losses	$ 295,348	Unlimited
Foreign tax loss carryforward	$ 1,505	2026 - 2033
State net operating losses	$ 282,871	Unlimited

As of December 31, 2024, the Company had U.S. federal net operating loss carryforwards (“NOLs”) of approximately $517.7 million, all of which are subject to limitation under Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”). Section 382 of the Code 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 2036.

Valuation Allowance

The Company recorded a valuation allowance of $3.3 million and $23.7 million as of December 31, 2024 and 2023, 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 NOLs or temporary differences 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 was 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. As of December 31, 2024, 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,		
	2024	2023	2022
Total unrecognized tax benefits, beginning balance	$ 989	$ 835	$ 696
Increases in unrecognized tax benefits as a result of:			
Tax positions taken during a prior period	(120)	154	100
Tax positions taken during the current period	723	—	39
Total unrecognized tax benefits, ending balance	$ 1,592	$ 989	$ 835

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 2021 through 2024 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, 2020 are closed, except to the extent of any NOL carryover balance.

QuarterNorth Acquisition

On March 4, 2024, the Company completed the QuarterNorth Acquisition, which is further discussed in Note 3 —*Acquisitions and Divestitures*. The Company recognized a net deferred tax liability of $168.1 million in its purchase price allocation as of the acquisition date to reflect differences between tax basis and the fair value of QuarterNorth'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. Further analysis will be performed upon filing QuarterNorth's tax returns that may result in a change to the net deferred tax liability recognized.

Note 13 — 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 and PSUs.

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,		
	2024	2023	2022
Net income (loss)	$ (76,393)	$ 187,332	$ 381,915
Weighted average common shares outstanding — basic	175,605	119,894	82,454
Dilutive effect of securities	—	858	1,229
Weighted average common shares outstanding — diluted	175,605	120,752	83,683
Net income (loss) per common share:			
Basic	$ (0.44)	$ 1.56	$ 4.63
Diluted	$ (0.44)	$ 1.55	$ 4.56
Anti-dilutive potentially issuable securities excluded from diluted common shares	2,084	1,353	865

Note 14 — Related Party Transactions

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. Bain held approximately 8.4% of the Company's outstanding shares of common stock as of December 31, 2024 based on SEC beneficial ownership reports filed by Bain. Adage ceased being a beneficial owner of more than five percent of the Company's common stock as of December 31, 2023 based on a SEC beneficial ownership report filed by Adage in February 2024.

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.

Slim Family and Affiliates

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. In connection with the Company's underwritten public offering during January 2024 as further described in Note 10 — *Stockholders' Equity*, Control Empresarial further increased their holding of the Company's outstanding stock. Control Empresarial held approximately 24.2% of the Company's outstanding shares of common stock as of December 31, 2024 based on SEC beneficial ownership reports filed by Control Empresarial.

On December 16, 2024, the Company entered into a cooperation agreement ("Cooperation Agreement") with Control Empresarial. Pursuant to the Cooperation Agreement, Control Empresarial agreed during the term of the Cooperation Agreement that it would not acquire, agree or seek to acquire or make any proposal or offer to acquire, or announce any intention to acquire, directly or indirectly, beneficially or otherwise, any voting securities of the Company (other than in connection with a stock split, stock dividend or similar corporate action initiated by the Company) if, immediately after such acquisition, Control Empresarial and the other members of its investor group, collectively, would, in the aggregate, beneficially own more than 25.0% of the outstanding shares of any class of voting securities of the Company. The Cooperation Agreement expires December 16, 2025, but is subject to early termination upon the occurrence of certain events described in the Cooperation Agreement.

The Slim Family own a majority stake in Carso. Carso is a public stock company incorporated in Mexico, which holds the shares of a group of companies that primarily operate in the commercial, industrial, infrastructure and construction and energy sectors. Carso, through its Zamajal subsidiary, has an ownership interest in Talos Mexico. See Note 7 – *Equity Method Investments* for additional information on Talos Mexico. As of December 31, 2024, Carso owes the Company $2.3 million related to advisory services the Company provided in connection with the Lakach Deepwater natural gas field off Mexico's southeastern coast near Veracruz.

Grupo Financiero Inbursa, S.A.B. de C.V. ("GFI") is a Mexico-based holding company engaged, through its subsidiaries, in the financial sector. The company's main activities are structured in four business lines: commercial banking, asset management, insurance and investment banking. The Slim Family own a majority stake in GFI. Banco Inbursa, S.A., Institución de Banca Múltiple, Grupo Financiero Inbursa ("Banco Inbursa") is a wholly owned banking subsidiary of GFI.

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 paid Banco Inbursa, an advisory fee of approximately $2.7 million. See Note 8 – *Debt* for additional information regarding the issuance of the second-priority senior secured notes.

Equity Method Investments

The Company had a $0.7 million and $5.5 million related party receivable from various equity method investments as of December 31, 2024 and 2023, respectively. These amounts are 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 15 — 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. The Company paid the judgment of $14.4 million, inclusive of Mr. Dunwoody's legal fees and interest, during the year ended December 31, 2024.

Firm Transportation Commitments

The Company has firm transportation agreements in place with transportation pipelines for future transportation of oil production. The Company is obligated to transport a minimum monthly oil volume or pay for any deficiencies for years 2025 through 2030. Our production is currently expected to exceed the minimum monthly volume in the periods provided in the agreements.

The table below summarizes the future minimum transportation fees under the Company's commitment as of December 31, 2024 (in thousands):

2025	$	5,439
2026		5,718
2027		9,249
2028		10,619
2029		4,465
Thereafter		1,453
Total	$	36,943

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 America.

As of December 31, 2024, the Company had secured performance bonds from third party sureties totaling $1.5 billion. The cost of securing these bonds is reflected as "Interest expense" on the Consolidated Statements of Operations. Additionally, as of December 31, 2024, the Company had secured letters of credit issued under its Bank Credit Facility totaling $42.4 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, 2024 (in thousands):

	2025	2026	2027	2028	2029	Thereafter	Total
Vessel Commitments[1]	$ 99,069	$ —	$ —	$ —	$ —	$ —	$ 99,069
Committed purchase orders[2]	40,668	—	—	—	—	—	40,668
Other commitments	19,082	16,493	9,249	10,619	4,465	1,453	61,361
Total	$ 158,819	$ 16,493	$ 9,249	$ 10,619	$ 4,465	$ 1,453	$ 201,098

(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.

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 America, 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,		
	2024	2023	2022
Balance, beginning of period	$ 15,564	$ 54,269	$ 24,336
Additions	6,168	266	8,900
Obligations assumed	1,326	—	—
Changes in estimate	2,391	11,613	22,658
Settlements	(5,447)	(50,584)	(1,625)
Balance, end of period	$ 20,002	$ 15,564	$ 54,269
Less: Current portion	5,453	3,280	42,069
Long-term portion	$ 14,549	$ 12,284	$ 12,200

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.

QuarterNorth Registration Rights Agreement

In connection with the Company's entry into the QuarterNorth Merger Agreement, on March 4, 2024, the Company entered into a registration rights agreement (the "QNE Registration Rights Agreement") with certain stockholders of QuarterNorth (collectively, the "RRA Holders"). Pursuant to the QNE Registration Rights Agreement, the Company granted the RRA Holders certain demand, "piggy-back" and shelf registration rights with respect to the shares of the Company's common stock received in connection with the QuarterNorth Acquisition, subject to certain customary thresholds and conditions. The Company is obligated to pay certain expenses of the RRA Holders incurred in connection with the exercise of their rights under the QNE Registration Rights Agreement and indemnify them for certain securities law matters in connection with any registration statement filed pursuant thereto.

Note 16 — Segment Information

The Company's operations were managed through two operating segments through March 18, 2024: (i) Upstream Segment and (ii) CCS Segment both of which are reportable. The CCS Segment was divested in March 2024. A reportable segment is an operating segment that meets materiality thresholds. The 10% tests, as prescribed by the segment reporting accounting guidance, are based on the reported measures of revenue, profit, and assets that are used by the Company's CODM to assess performance and allocate resources. The QuarterNorth Acquisition did not change the Company's reportable segment determinations and is included in the Upstream Segment. The CODM currently is the executive management team comprised of the General Counsel, Chief Financial Officer, and Head of Operations, each of whom are serving as Co-President, managing the Office of Interim Chief Executive Officer ("Office of the Interim CEO").

The profit or loss metric used to evaluate segment performance is net income as reported in the Company's Consolidated Statement of Operations. Net income is used by the CODM to measure segment profit or loss, assess performance and make strategic capital resource allocations.

Prior to the divestment of the CCS Segment, corporate general and administrative expense include certain shared costs such as finance, accounting, tax, human resources, information technology and legal costs that were not directly attributable to each of operating segment. These expenses have been fully allocated to each operating segment. Segment accounting policies 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):

Year Ended December 31, 2024	**Upstream**	**CCS[(1)]**	**Total**
Revenues from external customers	$ 1,973,568	$ —	$ 1,973,568
Significant expenses:			
Lease operating expense:			
Direct operating and maintenance	(492,123)	—	(492,123)
Workover	(73,918)	—	(73,918)
Adjusted general and administrative expense[(2)]	(130,695)	(1,919)	(132,614)
Net cash received (paid) on settled derivative instruments	4,710	—	4,710
Interest expense	(187,432)	(206)	(187,638)
Other segment items:			
Other[(3)]	(23,048)	(8,472)	(31,520)
Depreciation, depletion and amortization	(1,023,512)	(46)	(1,023,558)
Accretion expense	(117,604)	—	(117,604)
Mark-to-market derivative fair value gain (loss)	(6,168)	—	(6,168)
Equity-based compensation expense	(14,415)	(47)	(14,462)
Gain on TLCS Divestiture[(4)]	—	100,482	100,482
Equity method investment income (loss)	(2,319)	(7,970)	(10,289)
Gain (loss) on extinguishment of debt	(60,256)	—	(60,256)
Income tax benefit (expense)	12,188	(17,191)	(5,003)
Net income (loss)	(141,024)	64,631	$ (76,393)
Segment Expenditures	$ 603,765	$ 17,519	$ 621,284

(1) The CCS Segment was an emerging business in the start-up phase of operations and the business did not generate any revenues.
(2) Includes general and administrative expense less transaction expenses and equity-based compensation. Corporate overhead allocated to the Upstream Segment and CCS Segment was $78.5 million and $0.4 million, respectively.
(3) Primarily includes transaction expenses offset by interest income for the Upstream Segment and transaction expenses for the CCS Segment. Transaction expenses include severance expense, costs related to the QuarterNorth Acquisition and costs related to the TLCS Divestiture. See further discussion in Note 3 — *Acquisition and Divestitures* and Note 11 — *Employee Benefits Plans and Share-Based Compensation*.
(4) See further discussion in Note 3 — *Acquisitions and Divestitures* for additional information.

Year Ended December 31, 2023		Upstream		CCS[(1)]		Total
Revenues from external customers	$	1,457,886	$	—	$	1,457,886
Significant expenses:						
Lease operating expense:						
Direct operating and maintenance		(374,481)		—		(374,481)
Workover		(15,140)		—		(15,140)
Adjusted general and administrative expense[(2)]		(88,333)		(10,423)		(98,756)
Net cash received (paid) on settled derivative instruments		(9,457)		—		(9,457)
Interest expense		(172,060)		(1,085)		(173,145)
Other segment items:						
Other[(3)]		(55,048)		4,159		(50,889)
Depreciation, depletion and amortization		(661,904)		(1,630)		(663,534)
Accretion expense		(86,152)		—		(86,152)
Mark-to-market derivative fair value gain (loss)		90,385		—		90,385
Equity-based compensation expense		(11,454)		(1,499)		(12,953)
Gain on the 2023 Mexico Divestiture[(4)]		66,180		—		66,180
Equity method investment income (loss)		120		(12,229)		(12,109)
Gain (loss) on partial sale of equity investment[(5)]		—		8,900		8,900
Income tax benefit (expense)		57,719		2,878		60,597
Net income (loss)	$	198,261	$	(10,929)	$	187,332
Segment Expenditures	$	733,669	$	40,961	$	774,630

(1) The CCS Segment was an emerging business in the start-up phase of operations and the business did not generate any revenues.

(2) Includes general and administrative expense less transaction expenses and equity-based compensation. Corporate overhead allocated to the Upstream Segment and CCS Segment was $49.3 million and $1.7 million, respectively.

(3) Primarily includes transaction expenses and decommissioning obligations for the Upstream Segment. Transaction expenses include costs related to the EnVen Acquisition, inclusive of severance expense. See further discussion in Note 3 — *Acquisition and Divestitures*, Note 11 — *Employee Benefits Plans and Share-Based Compensation* and Note 15 — *Commitments and Contingencies*.

(4) See further discussion in Note 3 — *Acquisitions and Divestitures.*

(5) Includes a gain on the funding of the capital carry of the Company's investment in Bayou Bend by Chevron of $8.6 million. See further discussion in Note 7 — *Equity Method Investments.*

Year Ended December 31, 2022	Upstream	CCS(1)	Total
Revenues from external customers	$ 1,651,980	$ —	$ 1,651,980
Significant expenses:			
Lease operating expense:			
Direct operating and maintenance	(289,120)	—	(289,120)
Workover	(18,972)	—	(18,972)
Adjusted general and administrative expense(2)	(63,689)	(8,968)	(72,657)
Net cash received (paid) on settled derivative instruments	(425,559)	—	(425,559)
Interest expense	(124,936)	(562)	(125,498)
Other segment items:			
Other(3)	(42,510)	(2,653)	(45,163)
Depreciation, depletion and amortization	(414,395)	(235)	(414,630)
Accretion expense	(55,995)	—	(55,995)
Mark-to-market derivative fair value gain (loss)	153,368	—	153,368
Equity-based compensation expense	(14,681)	(1,272)	(15,953)
Gain on settlements(4)	29,998	—	29,998
Equity method investment income (loss)	101	(1,166)	(1,065)
Gain (loss) on partial sale of equity investment(5)	—	15,287	15,287
Gain (loss) on extinguishment of debt	(1,569)	—	(1,569)
Income tax benefit (expense)	(2,425)	(112)	(2,537)
Net income (loss)	$ 381,596	$ 319	$ 381,915
Segment Expenditures	$ 452,674	$ 2,778	$ 455,452

(1) The CCS Segment was an emerging business in the start-up phase of operations and the business did not generate any revenues.

(2) Includes general and administrative expense less transaction expenses and equity-based compensation. Corporate overhead allocated to the Upstream Segment and CCS Segment was $49.2 million and $1.6 million, respectively.

(3) Primarily includes decommissioning obligations and transaction expenses for the Upstream Segment. Transaction expenses include costs related to the EnVen Acquisition. See further discussion in Note 3 — *Acquisition and Divestitures* and Note 15 — *Commitments and Contingencies*.

(4) 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 15 — *Commitments and Contingencies.*

(5) Includes a gain on the funding of the capital carry of the Company's investment in Bayou Bend by Chevron of $1.4 million and a $13.9 million gain on the partial sale of its investment in Bayou Bend to Chevron. See further discussion in Note 7 — *Equity Method Investments.*

The following table presents the reconciliation of Segment Expenditures to the Company's consolidated totals (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Segment Expenditures:			
Total reportable segments	$ 621,284	$ 774,630	$ 455,452
Change in capital expenditures included in accounts payable and accrued liabilities	29,423	(9,199)	(60,011)
Plugging & abandonment	(108,789)	(86,615)	(69,596)
Decommissioning obligations settled	(5,447)	(50,584)	(1,625)
Investment in CCS intangibles and equity method investees	(22,988)	(40,946)	(2,778)
Other deferred payments	(2,389)	(1,545)	—
Non-cash well equipment transfers	(3,412)	(27,731)	(6)
Other	1,232	3,424	1,728
Exploration, development and other capital expenditures	$ 508,914	$ 561,434	$ 323,164

Note 17 — 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 depreciation, depletion and amortization ("DD&A") as of the dates indicated are presented below (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Consolidated Entities:			
Proved properties	$ 9,784,832	$ 7,906,295	$ 5,964,340
Unproved oil and gas properties, not subject to amortization(1)	587,238	268,315	154,783
Total oil and gas properties	10,372,070	8,174,610	6,119,123
Less: Accumulated DD&A	5,163,844	4,143,491	3,484,590
Net capitalized costs	$ 5,208,226	$ 4,031,119	$ 2,634,533
DD&A rate (Per Boe)	$ 30.11	$ 27.23	$ 18.95
Company's Share of Equity Investees:			
Unproved oil and gas properties, not subject to amortization	$ 58,723	$ 56,579	$ —

(1) Amount includes $111.4 million of unproved properties, not subject to amortization, related to the Company's operations in offshore Mexico for the year ended December 31, 2022.

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,		
	2024	2023	2022
Consolidated Entities:			
Property acquisition costs:			
Proved properties	$ 1,085,324	$ 951,703	$ —
Unproved properties, not subject to amortization	380,129	249,688	2,221
Total property acquisition costs	1,465,453	1,201,391	2,221
Exploration costs(1)	129,400	161,296	125,889
Development costs	602,607	805,148	541,512
Total costs incurred	$ 2,197,460	$ 2,167,835	$ 669,622
Company's Share of Equity Investees:			
Exploration costs	$ 2,144	$ 290	$ —

(1) Year ended December 31, 2022 amount includes $1.2 million of exploration costs related to the Company's operations in offshore Mexico.

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. All of the Company's proved oil, natural gas and NGL reserves are located in the U.S. Gulf of America.

At December 31, 2024 all proved reserves were estimated by Netherland, Sewell & Associates, Inc ("NSAI"), independent petroleum engineers and geologists. At December 31, 2023 and 2022, 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 NSAI.

The following table presents the Company's estimated proved reserves at its net ownership interest:

	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Oil Equivalent (MBoe)
Consolidated Entities:				
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)
Acquisition 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
Revision of previous estimates	(599)	(30,186)	698	(4,932)
Production	(24,078)	(41,078)	(2,969)	(33,893)
Acquisition of reserves	51,376	99,683	4,834	72,824
Extensions and discoveries	5,534	9,684	329	7,477
Total proved reserves at December 31, 2024	143,048	217,974	14,865	194,242
Total Proved Developed Reserves as of:				
December 31, 2022	80,285	161,727	9,315	116,555
December 31, 2023	98,225	141,823	9,957	131,819
December 31, 2024	108,479	175,139	12,733	150,402
Total Proved Undeveloped Reserves as of:				
December 31, 2022	10,774	57,824	3,613	24,024
December 31, 2023	12,590	38,048	2,016	20,947
December 31, 2024	34,569	42,835	2,132	43,840

During 2024, proved reserves increased by 41.5 MMBoe primarily due to the acquisition of reserves of 72.8 MMBoe in connection with the QuarterNorth Acquisition and Monument Acquisition as well as 7.5 MMBoe of estimated proved reserves from extensions and discoveries primarily from evaluations of the Brutus Field, Ewing Bank 953 Field, Sunspear Field and Pompano Field in the Deepwater area. This increase was partially offset by a decrease of 33.9 MMBoe of production and a decrease of 4.9 MMBoe from revisions of previous estimates. The revisions were primarily due to a 11.3 MMBoe of downward revisions primarily related to derecognizing proved developed non-producing and PUD cases in the Phoenix Field, Brutus Field and Prince Field, all located in the Deepwater area. Additionally, due to the Deepwater assets acquired via the QuarterNorth Acquisition and the Monument Project, the Company reassessed its drilling and development plan resulting in the derecognition of 4.2 MMBoe of PUD reserves primarily associated non-operated fields located in the Shelf & Gulf Coast area. These downward revisions were offset by upward revisions 15.3 MMBoe due to the successful drilling of the Katmai West #2 development well in addition to positive well performance primarily in the Katmai Field and Big Bend Field located in the Deepwater area.

During 2023, proved reserves increased by 12.2 MMBoe primarily due to acquisition 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 Deepwater 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 Deepwater 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 Deepwater 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 Deepwater 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,		
	2024	2023	2022
Consolidated Entities:			
Future cash inflows	$ 11,660,546	$ 9,425,055	$ 10,674,896
Future costs:			
Production	(3,436,232)	(3,090,491)	(1,906,752)
Development and abandonment	(3,301,619)	(2,358,368)	(1,873,453)
Future net cash flows before income taxes	4,922,695	3,976,196	6,894,691
Future income tax expense	(845,894)	(589,413)	(1,114,409)
Future net cash flows after income taxes	4,076,801	3,386,783	5,780,282
Discount at 10% annual rate	(512,597)	(343,295)	(1,411,834)
Standardized measure of discounted future net cash flows	$ 3,564,204	$ 3,043,488	$ 4,368,448

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,		
	2024	2023	2022
Oil price per Bbl	$ 75.51	$ 78.56	$ 96.03
Natural gas price per Mcf	$ 2.45	$ 2.75	$ 6.80
NGL price per Bbl	$ 21.91	$ 18.77	$ 33.89

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,		
	2024	2023	2022
Consolidated Entities:			
Standardized measure, beginning of year	$ 3,043,488	$ 4,368,448	$ 3,440,611
Sales and transfers of oil, net gas and NGLs produced during the period	(1,406,150)	(1,065,814)	(1,340,400)
Net change in prices and production costs	(123,537)	(2,835,125)	2,388,442
Changes in estimated future development and abandonment costs	193,810	(19,877)	(84,391)
Previously estimated development and abandonment costs incurred	47,016	202,503	20,107
Accretion of discount	485,409	518,110	392,600
Net change in income taxes	(181,190)	357,321	(327,265)
Purchases of reserves	1,638,000	2,033,852	—
Sales of reserves	—	—	(5,218)
Extensions and discoveries	74,126	90,244	202,239
Net change due to revision in quantity estimates	(162,041)	(484,423)	(255,743)
Changes in production rates (timing) and other	(44,727)	(121,751)	(62,534)
Standardized measure, end of year	$ 3,564,204	$ 3,043,488	$ 4,368,448

Note 18 — Subsequent Events

Monument Additional Working Interest Acquisition

For additional information, see Note 3 — *Acquisitions and Divestitures.*

Schedule I. Condensed Financial Information of Registrant

TALOS ENERGY INC. (PARENT ONLY)
BALANCE SHEETS
(In thousands, except share amounts)

	Year Ended December 31,	
	2024	2023
ASSETS		
Current assets:		
Accounts receivable:		
Other, net	$ —	$ 100
Prepaid assets	203	221
Other current assets	19	19
Total current assets	222	340
Other long-term assets:		
Investments in subsidiaries	3,006,909	2,246,908
Total assets	$ 3,007,131	$ 2,247,248
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 333	$ 316
Accrued liabilities	544	705
Other current liabilities	162	124
Total current liabilities	1,039	1,145
Long-term liabilities:		
Other long-term liabilities	246,387	90,952
Total liabilities	247,426	92,097
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Preferred stock; $0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of December 31, 2024 and 2023, respectively	—	—
Common stock; $0.01 par value; 270,000,000 shares authorized; 187,434,908 and 127,480,361 shares issued as of December 31, 2024 and 2023, respectively	1,874	1,275
Additional paid-in capital	3,274,626	2,549,097
Accumulated deficit	(424,110)	(347,717)
Treasury stock, at cost; 7,417,385 and 3,400,000 shares as of December 31, 2024 and 2023, respectively	(92,685)	(47,504)
Total stockholders' equity	2,759,705	2,155,151
Total liabilities and stockholders' equity	$ 3,007,131	$ 2,247,248

See accompanying notes.

TALOS ENERGY INC. (PARENT ONLY)
STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31,		
	2024	2023	2022
Operating expenses:			
General and administrative expense	$ 3,234	$ 2,708	$ 2,145
Total operating expenses	3,234	2,708	2,145
Operating income (expense)	(3,234)	(2,708)	(2,145)
Other income (expense)	(1)	(1)	(1)
Equity earnings (loss) from subsidiaries	(83,986)	128,888	385,968
Net income (loss) before income taxes	(87,221)	126,179	383,822
Income tax benefit (expense)	10,828	61,153	(1,907)
Net income (loss)	$ (76,393)	$ 187,332	$ 381,915

See accompanying notes.

TALOS ENERGY INC. (PARENT ONLY)
STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net cash provided by (used in) operating activities	$ (1,403)	$ (1,836)	$ (809)
Cash flows from investing activities:			
Investments in subsidiaries	(389,138)	—	—
Distributions from subsidiaries	48,005	49,340	809
Net cash provided by (used in) investing activities	(341,133)	49,340	809
Cash flows from financing activities:			
Issuance of common stock	387,717	—	—
Purchase of treasury stock	(45,181)	(47,504)	—
Net cash provided (used in) by financing activities	342,536	(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, 2024

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.

[THIS PAGE INTENTIONALLY LEFT BLANK]

BOARD OF DIRECTORS

NEAL P. GOLDMAN
Chairman of the Board Managing Member, SAGE Capital Investments, LLC

PAUL GOODFELLOW
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

RICHARD SHERRILL
President, Howard Energy

CHARLES M. SLEDGE
Retired Chief Financial Officer, Cameron International

SHANDELL SZABO
Retired Vice President of U.S. Exploration, Anadarko Petroleum Corporation

MANAGEMENT TEAM

PAUL GOODFELLOW
President and Chief Executive Officer

SERGIO L. MAIWORM, JR.
Executive Vice President and Chief Financial Officer

WILLIAM S. MOSS III
Executive Vice President, General Counsel and Secretary

JOHN B. SPATH
Executive Vice President and Head of Operations

GREG BABCOCK
Vice President and Chief Accounting Officer

JIM BRYSCH
Vice President – Marketing

WILLIAM P. BUNKERS
Vice President – Production Operations

MEGAN DICK
Vice President - Human Resources

DEBORAH HUSTON
Vice President and Deputy General Counsel

CLAY JEANSONNE
Vice President – Investor Relations

C. GORDON LINDSEY
Vice President - Corporate Development

FRANCISCO NOYOLA
Vice President – Mexico

JOEL PLAUCHE
Vice President – HSE, Regulatory and Compliance

JOE SAUVAGEAU
Vice President – Asset Development

TRUITT SMITH
Vice President – Geoscience

STOCKHOLDER INFORMATION

SHAREHOLDER SERVICES
Computershare Mailing: P.O. Box 505000 Louisville, KY 40233
1-800-962-4284 (Toll-Free)
1-781-575-3120 (International)

STOCK EXCHANGE LISTING
New York Stock Exchange
Symbol: TALO

INVESTOR RELATIONS CONTACT
investor@talosenergy.com

ANNUAL MEETING
May 29, 2025 10:00 a.m. CT
Three Allen Center
333 Clay St., Suite 3300
Houston, TX 77002

OVERNIGHT MAIL
462 South 4th Street, Suite 1600
Louisville, KY 40202

FORM 10-K
Copies are available at www.talosenergy.com

AUDITORS
Ernst & Young, Houston, TX

SEC FILINGS
Our filings made with the SEC can be found under the "SEC Filings" tab within the "Filings & Reports" section of our website at www.talosenergy.com

WEBSITE
www.talosenergy.com

CORPORATE OFFICE
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713-328-3000

TALOS ENERGY

333 Clay St., Suite 3300
Houston, Texas 77002

713.328.3000

www.talosenergy.com

investor@talosenergy.com