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, 2025

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

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

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	TALO	New York Stock Exchange

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the closing price of the shares of common stock on the New York Stock Exchange on June 30, 2025, was $1,106,796,185.

The number of shares of registrant's Common Stock outstanding as of February 17, 2026 was 168,514,683.

Portions of the registrant's definitive proxy statement relating to the 2026 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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GLOSSARY

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

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

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

BOEM — Bureau of Ocean Energy Management.

BSEE — Bureau of Safety and Environmental Enforcement.

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

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

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

***CO_2* —** Carbon dioxide.

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

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

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

***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.

***MBopd* —** One thousand barrels of oil 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, discounted at 10% annually, of estimated future revenues to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production costs, future development costs, and abandonment 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 costs, production costs, abandonment costs, 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," "potential," "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 beliefs, based on currently available information, as to the outcome and timing of future events. Forward-looking statements may include, but are not limited to, 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, acquisitions, recompletions or enhanced recovery;
- financial strategy, borrowing base under our credit agreement, availability of financing sources and under our credit facility, liquidity position and capital required for our development program, acquisitions and other capital expenditures;
- realized oil and natural gas prices;
- changes in tariffs, trade barriers, price and exchange controls and other regulatory requirements including such changes that may be implemented by the current or future administrations or foreign governments, and the impact of such policies on us, our customers and suppliers and the global economic environment;
- volatility in the political, legal and regulatory environments where we currently or in the future may operate;
- 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, including a potential increase in OPEC oil supply and any related impact on global oil prices and domestic oil production;
- our hedging strategy and results;
- future drilling plans;
- availability of pipeline connections and other infrastructure on economic terms;
- competition, government regulations, including financial assurance requirements, and legislative and political developments;
- our ability to obtain permits and governmental approvals;
- pending legal, governmental or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our integration of acquisitions and the anticipated post-acquisition performance of the Company;
- future leasehold or business acquisitions on desired terms;
- costs of developing, acquiring or abandoning 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, timeline and results with respect to our investment in the Zama asset;
- uncertainty regarding our future operating results and our future revenues and expenses;
- anticipated capital efficiency, margin enhancement and organizational improvements and additional cash flow;
- our ability to obtain surety bonds on commercially reasonable terms; expected collateral requirements under existing or future surety agreements; market factors impacting the availability of surety bonds;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit, surety bonds and other secured debt;
- 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; foreign wars and conflicts, including the lack of a resolution to the war in Ukraine and ongoing hostilities in Israel and the Middle East and recent U.S. intervention in Venezuela, and their impact on commodity markets; the impact of any pandemic and governmental measures related thereto; lack of necessary infrastructure, transportation and storage capacity as a result of oversupply, government and regulations; political risks, including a global trade war or the impact of any prolonged federal government shutdown or lapse in federal appropriations that could disrupt our operations and future drilling plans and opportunities; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes, winter storms and loop currents; cybersecurity threats and incidents; elevated 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 and future 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 and labor policies, including the imposition of increased tariffs and the 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 used by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions upward or downward 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 and prolonged price declines could materially adversely affect our business, financial condition, results of operations, cash flows, access to capital, and our ability to replace and grow future production.
- If we are unable to replace oil and natural gas reserves, we may not be able to sustain or grow our business.
- Future exploration and drilling results are uncertain and involve substantial costs.
- Our current operations are primarily concentrated in a single geographic region, making us vulnerable to regional risks.
- Global geopolitical tensions may increase volatility in oil, gas and NGL prices and could adversely affect our business.
- Our actual recovery of reserves may differ substantially from our proved reserve estimates.
- Our future asset retirement obligations, including plugging and abandonment expenditures and decommissioning costs, are difficult to predict, may vary significantly from period to period and could materially adversely affect our current and future financial results.
- We risk losing leases if we cannot drill before such leases expire.
- We depend on infrastructure to market and deliver our production.
- Inflation and interest rate changes could increase our costs.
- We may not be able to obtain sufficient surety bonds on reasonably acceptable terms to conduct our business.
- Technology and cybersecurity threats could disrupt our operations and cause reputational and financial harm to our business.
- We have limited control over the activities on properties we do not operate.
- Hedging transactions may limit our potential gains and expose us to other risks.
- Compliance with environmental laws, including legal requirements related to marine life and endangered and threatened species, could increase our costs and limit operations.
- Regulatory changes could restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to leases, which could have a material adverse effect on our business, financial condition or results of operations.
- Production shut-ins could increase costs and reduce future production.
- Severe weather or public health events could disrupt production and reduce revenues.
- We are not insured against all of the operating risks to which our business is exposed.
- Our actual production could differ materially from our forecasts.
- Our strategy emphasizes Deepwater exploration and development, which involves significantly higher operational and financial risks than operations in shallower waters. Deepwater activities in the Gulf of America are complex, capital-intensive, and subject to a wide range of uncertainties.
- Intense industry competition could limit our growth and increase costs.
- The loss of a significant customer could materially reduce our revenue and materially adversely affect our business.
- We rely on skilled and experienced personnel, and shortages in such personnel, higher labor costs or the loss of key management could adversely affect our ability to operate.
- We have various contractual commitments. Our failure to satisfy these commitments could adversely affect our results of operations and financial position.
- Changes in U.S. trade policy, including tariffs or other restrictions, could increase costs and adversely affect our business.
- We may not realize expected benefits from future acquisitions, and integration challenges could harm our business.
- Acquisitions and current assets expose us to potentially significant liabilities, including abandonment obligations.
- Litigation outcomes could materially affect our financial condition.
- Lower oil and natural gas prices and other factors have resulted in, and may in the future result in additional, ceiling test impairments and other impairments of our asset carrying values.

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

- Our debt level and related covenants in our current or future credit agreement and indentures could restrict our operations, and failure to comply with the covenants could result in accelerated payment obligations.

- The Carlos Slim family's significant ownership and voting power may create conflicts of interest and influence shareholder votes and major strategic decisions.
- A financial crisis or disruption in credit markets could limit our access to funding and adversely impact our ability to do business.
- We require substantial capital to fund our operations and replace our production and may not be able to obtain financing on acceptable terms.
- As a holding company, we depend on distributions from Talos Production Inc. and our subsidiaries to meet our obligations.
- Future sales, or the perception of future sales, of our stock could lower our share price and dilute the holdings of our existing stockholders.
- Stockholder activism could disrupt our business and harm our 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

In June 2025, we announced our enhanced corporate strategy to position us as a leading pure-play offshore exploration and production company. Our strategy includes the following three pillars:

- **Improve the business every day.** Target increased annualized free cash flow by improving our existing operations through capital efficiency, margin enhancement, commercial opportunities and general organizational improvements.
- **Grow production and profitability.** Invest in high-margin organic projects, complemented by disciplined, accretive bolt-on acquisitions in Deepwater basins, which will enhance production and profitability.
- **Build a long-lived, scaled portfolio.** Participate in greenfield developments, explore for large resource potential, acquire and develop projects with significant reserves, and evaluate opportunities within the Gulf of America and other conventional basins. A scaled portfolio will provide us with significant growth potential and ultimately the ability to generate long-term consistent free cash flow.

This strategy is underpinned by a disciplined capital allocation framework which prioritizes investing in projects expected to generate robust returns through commodity cycles, returning cash to shareholders, maintaining a strong balance sheet, and growing through selective opportunities.

Properties

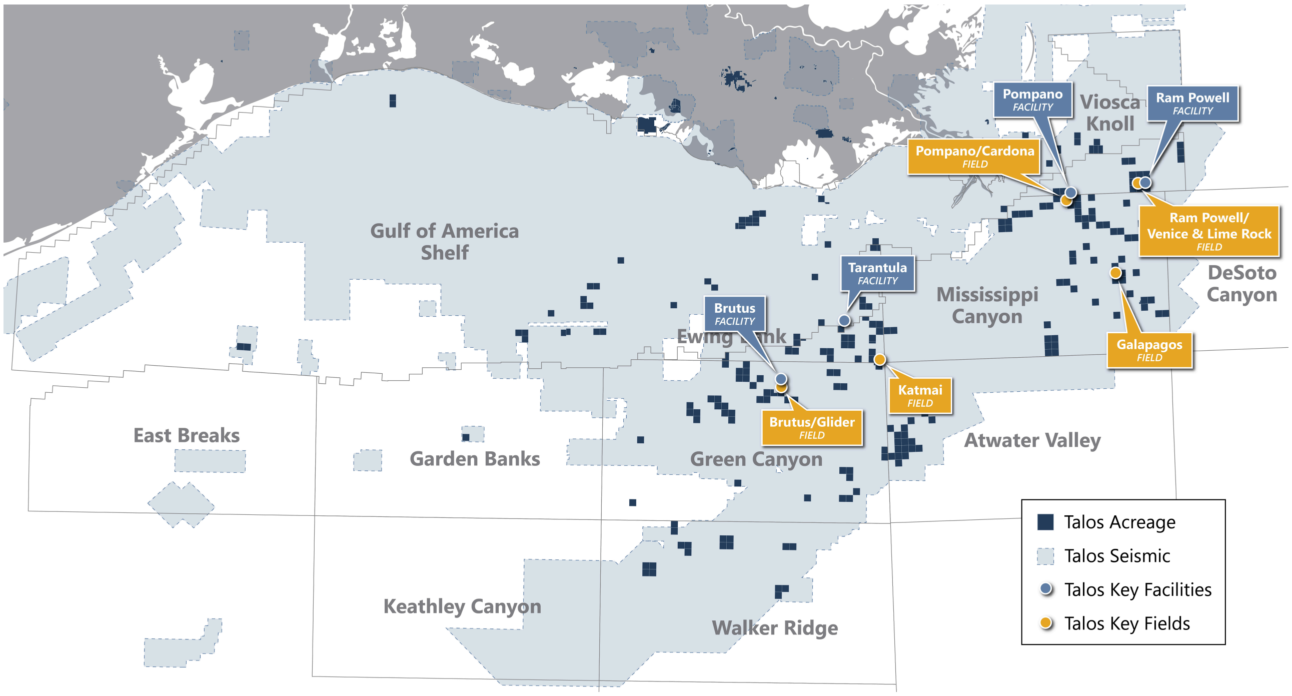
U.S. Gulf of America

Our activities are primarily concentrated in the Deepwater area but we also have operations on the Shelf and Gulf Coast. The Deepwater region in the Central U.S. Gulf of America remains a vital basin 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. We concentrate in areas characterized by clearly defined infrastructure, well-known production history and geological well control, which reduces operational and investment risk.

The following table sets forth a summary of certain key 2025 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	159,697	78 %	15 %	7 %	78 %	31,047	81 %
Shelf & Gulf Coast	14,996	35 %	52 %	13 %	85 %	3,487	76 %
Total United States	174,693	75 %	19 %	6 %	78 %	34,534	81 %

As of December 31, 2025, our acreage, seismic and key facilities and fields in the U.S. are summarized in the illustration below:



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, a Talos-led consortium (the "Block 7 Consortium") was awarded a production sharing contract ("PSC") covering Block 7 with a term of thirty years, extendable for two additional five-year periods. Talos Energy Mexico 7, S. de R.L. de C.V. ("Talos Mexico") was named operator of Block 7. On March 22, 2022, Block 7 was unitized with a neighboring block operated by Petróleos Mexicanos ("PEMEX").

Talos Mexico, the Mexican affiliates of Harbour Energy ("Harbour Energy"), and PEMEX hold gross interests of 17.35%, 32.22%, and 50.43%, respectively, in the unitized Zama Field. On December 19, 2025, the Mexican Ministry of Energy ("SENER") approved the transfer of Block 7 operatorship from Talos Mexico to Harbour Energy. In addition, on December 29, 2025, SENER approved the transfer of operatorship of the Zama Field from PEMEX to Harbour Energy.

In September 2023, we closed the sale of a 49.9% equity stake in Talos Mexico to Zamajal, S.A. de C.V. ("Zamajal"), majority-owned by Grupo Carso, S.A.B. de C.V. ("Carso") (the "2023 Mexico Divestiture"). In December 2024, we entered into an agreement to sell an additional 30.1% equity interest in Talos Mexico to Zamajal (the "Incremental Mexico Equity Sale"). While we anticipate the Incremental Mexico Equity Sale will close before the end of the second quarter of 2026, 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* for additional information on the 2023 Mexico Divestiture; Note 7 — *Equity Method Investments* for additional information on both Talos Mexico and 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, 2025						
Proved developed producing	78,537	103,638	7,092	102,902		$ 2,419,008
Proved developed non-producing	22,494	52,782	2,552	33,843		438,503
Total proved developed	101,031	156,420	9,644	136,745		2,857,511
Proved undeveloped	29,595	38,180	1,990	37,948		331,526
Total proved	130,626	194,600	11,634	174,693	$ 2,804,857	$ 3,189,037
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

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,		
	2025	2024	2023
Consolidated Entities:			
Standardized measure	$ 2,804,857	$ 3,564,204	$ 3,043,488
Present value of future income taxes discounted at 10%	384,180	636,520	455,330
PV-10 (Non-GAAP)	$ 3,189,037	$ 4,200,724	$ 3,498,818

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, 2024	43,840	$ 881,182
Changes during the year:		
Extensions and discoveries	123	—
Revisions of previous estimates	(1,134)	(8,436)
Acquired	4,880	86,722
Conversion to proved developed	(9,761)	(225,496)
Total proved undeveloped reserves changes	(5,892)	(147,210)
Proved undeveloped reserves at December 31, 2025	37,948	$ 733,972

Our PUD reserves at December 31, 2025 decreased by 5.9 MMBoe, or 13% primarily due to:

Revisions of Previous Estimates — Downward revisions of 1.1 MMBoe are primarily related to the derecognition of approximately 2.0 MMBoe of PUD reserves associated with our South Timbalier 308 Field in the Deepwater area, resulting from a reassessment of the drilling and development plan following successful drilling at the Katmai Field. These downward revisions were partially offset by certain positive revisions at our Brutus Field driven by economics.

Acquired — Acquired PUD reserves of 4.9 MMBoe is primarily comprised of 4.5 MMBoe attributable to the acquisition of an incremental non-operated working interest in the Monument oil discovery (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 9.8 MMBoe are primarily attributable to successful conversion of proved undeveloped reserves at our Gunflint Field, Sunspear Field, Cardona Field, and Ewing Bank 953 Field, which are all 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, 2025 totaled $734.0 million, of which $703.5 million is attributable to our Deepwater area. 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 2026 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, 2025 and 2024, all proved reserves were estimated by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists. At December 31, 2023, 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;
- future development costs and abandonment costs associated with our proved reserves are reviewed by qualified individuals;
- 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 required that the independent petroleum engineers and geologists and our reserve quantities and calculation of the net present value of the reserves, collectively, varied by no more than 10% in the aggregate when the reserves audit was conducted for the year ended December 31, 2023, 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, 2025 and 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 as of December 31, 2025 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 an unqualified audit opinion on our proved reserves as of December 31, 2023 based upon its evaluation. 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. She is a member of the Society of Petroleum Engineers. The Director of Reserves reports directly to our Vice President of Strategic Planning.

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, 2025														
United States	2.0	0.8	1.0	0.4	3.0	1.2	3.0	1.1	—	—	3.0	1.1	6.0	2.3
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

Present Activities

As of December 31, 2025, 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	0.7	1.0	0.3	—	—
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 and gas production.

We have no firm sales commitments as of December 31, 2025.

Productive Wells

The number of our productive wells is as follows for the year ended December 31, 2025:

	Gross	Net
Consolidated Entities:		
Crude oil	216.0	161.1
Natural gas	70.0	28.8
Total[(1)]	286.0	189.9

(1) Includes 7.0 gross and 5.3 net wells with dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2025:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Consolidated Entities:						
United States:						
Deepwater	428,141	248,761	581,059	310,453	1,009,200	559,214
Shelf	228,209	155,486	54,935	37,724	283,144	193,210
Total United States	656,350	404,247	635,994	348,177	1,292,344	752,424
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, 2025 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
2026	97,920	40,678	—	—
2027	83,520	43,193	—	—
2028	29,426	15,924	—	—
2029	51,074	32,920	—	—
2030	5,760	1,728	—	—
2031 and beyond	368,294	213,734	3,261	572
Total	635,994	348,177	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,		
	2025	2024	2023
Consolidated Entities:			
Production Volumes:			
Crude oil (MBbls)	24,065	24,078	18,062
Natural gas (MMcf)	46,122	41,078	26,194
NGLs (MBbls)	2,782	2,969	1,767
Total (MBoe)	34,534	33,893	24,195
Percent of MBoe from crude oil	70 %	71 %	75 %
Average Sales Price (including commodity derivatives):			
Crude oil (per Bbl)	$ 68.18	$ 75.07	$ 73.59
Natural gas (per Mcf)	$ 3.70	$ 2.65	$ 3.32
NGLs (per Bbl)	$ 18.05	$ 20.85	$ 18.18
Average (per Boe)	$ 53.90	$ 58.37	$ 59.86
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 64.84	$ 75.01	$ 75.17
Natural gas (per Mcf)	$ 3.67	$ 2.57	$ 2.60
NGLs (per Bbl)	$ 18.05	$ 20.85	$ 18.18
Average (per Boe)	$ 51.55	$ 58.23	$ 60.26
Average Lease Operating Expense (per Boe)	$ 15.83	$ 16.70	$ 16.10

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 2025 total estimated proved reserves on December 31, 2025:

	Year Ended December 31,	
	2025	2024[(1)]
Production Volumes:		
Crude oil (MBbls)	3,578	2,254
Natural gas (MMcf)	7,934	4,898
NGLs (MBbls)	493	293
Total (MBoe)	5,393	3,363
Percent of MBoe from crude oil	66 %	67 %
Average Sales Price (excluding commodity derivatives):		
Crude oil (per Bbl)	$ 67.45	$ 79.28
Natural gas (per Mcf)	$ 3.98	$ 2.59
NGLs (per Bbl)	$ 27.70	$ 29.89
Average (per Boe)	$ 53.13	$ 59.52
Average Lease Operating Expense (per Boe)	$ 3.95	$ 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, 2025, 35%, 23% and 12% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company, Exxon Mobil Corporation and Chevron 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 exploration opportunities, high margin assets concentrated in the Deepwater and significant operating control give us a strong competitive position relative to many of our competitors.

Seasonality of Business

Offshore weather conditions in the U.S. Gulf of America, particularly during hurricane and tropical storm season, may cause significant, immediate fluctuations in oil and natural gas markets by causing temporary shut-ins of offshore oil and natural gas production and forcing shutdowns or damaging coastal refineries. These events reduce supply, often leading to rapid, short-term price spikes and supply volatility. 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. Laws and regulations related to our business continually evolve and change depending on the political climate and regulatory regime, but generally the exploration and production industry, including our business, has been subject to increasing environmental, health and safety governmental regulations. Changes to these regulatory requirements, increased enforcement or compliance obligations, and other legal challenges to such regulations could materially impact the timing, cost, scope and feasibility of our operations, and increase capital investment and ongoing operating costs. We monitor regulatory developments closely and adjust our operational practices to maintain compliance when planning and performing our offshore Deepwater exploration and development activities.

General Overview — Our oil and natural gas operations in the Gulf of America are subject to various federal, state, and local environmental, health and safety laws and regulations, primarily enforced by two agencies:

- BOEM oversees leasing, resource management, environmental review, and approval of exploration and development plans.
- BSEE oversees drilling safety, production operations, equipment standards, well integrity, spill preparedness, and decommissioning.

We must also comply with regulations under the Outer Continental Shelf Lands Act, the Clean Water Act, the Oil Pollution Act, and other federal and state statutes governing offshore operations, emissions, discharges, worker safety, and spill liability. Additionally, our activities are affected by evolving federal and state environmental and operational regulations, including offshore federal lease requirements, requirements related to the exploration, production, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment and reducing greenhouse gas (“GHG”) emissions; wildlife, habitat and water protection; decommissioning and related financial assurance requirements; and the health and safety of our employees, contractors and communities where our operations are located. An overview of material regulations to which our operations are subject is set forth below.

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, plugging and abandonment (“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 have in the past, curtailed our access to new federal leases. Any continued or future challenges or delays could prevent us from obtaining new federal leases. Recently, however, Congress and the Trump Administration have taken action to revoke or rescind certain actions that placed limitations on offshore oil and gas leasing and permitting.

The One Big Beautiful Bill Act (“OBBBA”), signed into law by President Trump in July 2025, mandated that BOEM conduct a minimum of thirty lease sales in the Gulf of America through the first half of 2040. BOEM conducted the first lease sale required under the OBBBA in December 2025. The remaining lease sales are expected to be held each March and August for the years 2026 through 2039, with the last of these mandated Gulf of America lease sales expected in March 2040. In addition to the lease sales required under the OBBBA, in November 2025, the Secretary of the Interior issued a Proposed National Outer Continental Shelf Oil and Gas Leasing Program to replace the existing 2024-2029 Five-Year Leasing Program, which began on July 1, 2024 and was set to continue through June 30, 2029. The November 2025 draft proposed program includes 34 OCS lease sales through 2031, though the substance and timing of the final program remains uncertain. 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 high bidders 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.

Our operations are subject to rigorous standards relating to well drilling and completion design, competency tests, operation and maintenance of blow-out preventers, real-time monitoring of Deepwater drilling activities, including high temperature, high pressure drilling activities, and enhanced reporting requirements. For example, in August 2023, BSEE, under the Biden Administration, 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 ("BOP") systems and other well control and operations requirements. The Trump Administration has requested comments on that final rule although it is not certain what actions the Trump Administration may take with respect to these standards, if any, once comments have been reviewed. Given the already extensive regulatory framework related to exploration and development activities in the Gulf of America, further legislative, executive and regulatory actions or other legal initiatives could result in significant costs, including increased capital expenditures and operating costs, that could adversely impact our business. Our failure to comply with legal requirements under the OCSLA, our leases or applicable regulations could ultimately result in BOEM or BSEE canceling one or more of our leases, which could adversely affect our financial condition and operations.

Furthermore, adverse weather conditions in the 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. BOEM and BSEE have periodically issued guidance in the design of platforms and related structures in light of environmental and oceanic conditions in the Gulf. More stringent requirements 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. If BOEM determines that a lessee does not have the financial ability to meet its decommissioning and other obligations, BOEM may require the lessee to post additional financial security as assurance. 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 forms of financial assurance in all cases.

There has been substantial uncertainty with respect to BOEM's financial assurance requirements in recent years. In April 2024, under the Biden Administration, BOEM issued a final rule entitled "Risk Management and Financial Assurance for OCS Lease and Grant Obligations" which significantly increased the amount of new supplemental financial assurance required from certain lessees and grant holders conducting operations on the OCS. The final rule, which became effective June 29, 2024, adopted a three-year phased compliance period for fully meeting BOEM's supplemental financial assurance demand. The final rule was challenged, and the United States District Court for the Western District of Louisiana granted a stay of litigation while the agency pursues efforts to suspend, revise, or rescind the final rule. The court's order temporarily limits full implementation of the final rule by limiting BOEM's ability to seek supplemental financial assurance to cases of sole liability properties and certain non-sole liability properties that are held by owners who are not financially strong, as described in the final rule, and that have no co-owners or predecessors who are financially strong. In May 2025, the DOI announced its intent to revise and develop a new rule that is consistent with the Trump Administration's 2020 proposed rule on financial assurance. Although the specific substance and timing of a revised rule cannot be predicted at this time, it is anticipated that the new revised rule will revert to BOEM's former policy of considering the financial strength of both co-owners and predecessors in title when determining whether supplemental financial assurance is required. Notwithstanding the status of the final rule or a new revised rule, BOEM has stated it will continue to require lessees on the OCS to provide financial assurance in instances where BOEM determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

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, 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 various regulatory bodies. Failure to comply can result in the imposition of monetary penalties, revocation of permits, recession of the PSC, suspension of operations, and ordered decommissioning of offshore facilities and systems. Previously, the National Hydrocarbons Commission ("CNH") was 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. However, in October 2024, the President of Mexico signed a constitutional reform dissolving the CNH. The former functions of CNH have been assigned to the National Energy Commission ("NEC"), an independent body under SENER.

In March of 2025, the new Hydrocarbons Sector Law (the "LSH") was adopted. The LSH replaces the Hydrocarbon Law, which was in force since August 2014.

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 Mexican regulatory bodies may impose new or revised requirements that could increase operating costs and/or 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 and the environment. Occupational safety and health and environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of wells, platforms and pipelines, including those associated with 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 the waters where we operate.

Environmental liabilities and regulatory costs related to environmental protection are inherent in exploration and development activities. Based on long-term regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to safety and health compliance and environmental protection have increased over the years and are likely to continue to increase in the future. 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). Offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted by legal challenges. Some environmental laws and regulations 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. The regulatory requirements related to our business frequently change and may become more stringent based on the political administration in office and resulting regulatory regime. There can be no assurance that material costs and liabilities will not be incurred in the future. More stringent regulatory requirements may result in increased costs of operations and acquisitions and decreased production and our business and financial results could be adversely affected.

We maintain insurance for spills, pollution and certain other environmental risks, although our insurance does not fully cover 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 us against pollution and similar environmental risks.

Water Discharges — Our discharges into waters of the United States are regulated by the federal Clean Water Act, as amended (“CWA”), and analogous state laws, which impose restrictions and strict controls related to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters. Failure to comply with the CWA may result in administrative, civil or criminal enforcement actions. Violations of the CWA can also 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”), imposes certain duties and liabilities on the owner or operator of a facility, vessel or pipeline that is a source of or that poses the substantial threat of an oil discharge, or the lessee or permittee of the area in which a discharging offshore facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages.

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 owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. 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. However, BOEM may increase this amount in certain situations, but in no event greater than $150 million. If OPA is amended to increase the minimum level of financial responsibility, we could experience difficulty in providing financial assurances, in the form of surety bonds or otherwise, sufficient to comply with a significantly heightened 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 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, which can lead to substantial delays in the issuance of federal permits. Following an Executive Order of President Trump, in February 2025, the White House's Council on Environmental Quality ("CEQ") released an interim final rule rescinding its regulations implementing NEPA. In May 2025, the Supreme Court issued its opinion in *Seven County Infrastructure Coalition v. Eagle County*, emphasizing the "substantial judicial deference" that courts must grant agencies when considering NEPA challenges. Federal agencies have begun preparing their own new or updated NEPA-implementing rules or guidelines and, in September 2025, the CEQ issued new guidance to federal agencies implementing NEPA to encourage them to limit their NEPA reviews, rely more heavily on sponsor-prepared documents, and streamline the NEPA process. The full impact of these developments remains unclear, but the NEPA process, which involves public input through comment 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.

Wildlife and Habitat Protection — The Endangered Species Act, as amended ("ESA"), was established to protect endangered and threatened species. If a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds, under the Migratory Bird Treaty Act, as amended ("MBTA"), and marine mammals under the Marine Mammal Protection Act, as amended ("MMPA").

Additionally, the U.S. Fish and Wildlife Service ("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 as endangered under the ESA. Further, in July 2023, NMFS proposed to designate approximately 28,300 square miles of the Gulf of America as critical habitat for the Rice's whale pursuant to a settlement agreement in a lawsuit. An amended settlement agreement further extended the deadline for NMFS to publish its final rule designating critical habitat for the Rice's whale to no later than July 15, 2027. In addition, in July 2023, the NMFS proposed a critical habitat for the Green sea turtle, which encompasses the majority of the 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. 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, in August 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 covered 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. The court thereafter extended the vacatur date to May 21, 2025, pursuant to a motion filed by NMFS. In May 2025, NMFS timely published its new Biological Opinion for the Gulf of America oil and gas program, superseding and replacing all prior biological opinions relating to the program. On the same day, two lawsuits were filed opposing the new Biological Opinion, one by several environmental groups (Sierra Club, the Center for Biological Diversity, Friends of the Earth and Turtle Island Restoration Network) who filed in the federal district court for the District of Maryland, and the other by the State of Louisiana, the American Petroleum Institute ("API") and Chevron U.S.A. Inc. who filed in the Western Louisiana District Court. Both lawsuits seek declaratory and injunctive relief. On January 23, 2026, the Western Louisiana District Court judge issued a summary judgment in favor of the State of Louisiana, API and Chevron U.S.A. Inc., and found the 2025 Biological Opinion unlawful. The 2025 Biological Opinion was remanded, without vacatur, to NMFS to correct the Biological Opinion's deficiencies. The 2025 Biological Opinion will remain active to avoid disruptive consequences to regulated parties. The outcome of the environmental groups' challenge in the Maryland District Court remains uncertain at this time.

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. Regulatory agencies and environmental groups have periodically examined whether certain exploration and production wastes should be reclassified under RCRA, and future regulatory actions could result in the loss or narrowing of the current exemption. Any such changes could significantly increase our waste-handling, storage, transportation, and disposal costs. 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. In recent years, the EPA has developed, and, in the future may continue 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 2020, the EPA under the Trump Administration published a decision to retain the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone that was set by the EPA in 2015. We cannot predict what further actions, if any, the Trump Administration may take with respect to these standards, or on what timeline it may take such actions. 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.

Climate Change — In recent years, the threat of climate change has attracted 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. In the United States, no comprehensive climate change legislation has been implemented at the federal level, though 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. However, following the change in U.S. presidential administrations, proposals have been made to repeal or otherwise modify these requirements and the EPA's GHG "Endangerment Finding," which underpins the majority of EPA's GHG regulations. In February, the EPA finalized a rule repealing the Endangerment Finding; however, the rule has been challenged. It is uncertain at this time what impact the repeal of the Endangerment Finding will have on current or anticipated EPA regulations, and it is not possible to determine the outcome of the challenges to the repeal.

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. 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.

Although we do not currently operate in California, the state has enacted laws requiring additional disclosure with respect to certain climate-related risks and GHG emission reduction claims. Although these laws are subject to legal challenge, to the extent compliance becomes required, any non-compliance with these 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.

Regulators and scientific bodies have identified GHG concentrations in the atmosphere as a factor that may contribute to changes in climatic patterns, including increased frequency and severity of extreme weather events. 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.

FERC anti-manipulation regulations establish 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. FERC also has authority to impose civil penalties for violations of the Energy Policy Act of 2005, the NGA and the NGPA, 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 FERC’s anti-manipulation regulations and civil penalty authority 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. Since 1978, the United States Congress has removed 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.

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.

Worker Health and Safety — We are subject to the Occupational Safety and Health Act, as amended (“OSHA”), and comparable state statutes that regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires that certain information about hazardous materials used or produced in our operations be maintained and provided to employees, state and local government authorities and citizens. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Human Capital

Our approach to human capital management continues to evolve as we grow our business. We strive to manage our employees in a way that supports our business strategy and promotes employee development.

Policies — Our Code of Business Conduct 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 the basic human rights tenets that we expect all employees, contractors, vendors, partners and suppliers, to follow.

Our Code of Business Conduct and Human Rights Policy are monitored 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 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, goals, and programs with the support of the Human Resources function, led by the Chief Human Resources Officer, who reports to the CEO.

The Compensation Committee of our Board (the “Compensation Committee”) oversees 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, and social and human capital risks.

Workforce Composition — As of December 31, 2025, we employed approximately 700 employees located primarily in Texas, Louisiana and Mexico. Approximately 400 (54%) of these employees are in our offshore operations and seven 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 as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement.

Safety — Safety is a core value and number one priority in the operation of our business. Our focus on safety starts at the top with our Board, CEO, and Executive Vice President & Head of Operations, who is directly responsible for all safety initiatives, and the 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, we have implemented key behavior-based safety programs and initiatives to empower a safety-focused culture and intend to implement a human and organizational planned principles program beginning in 2026. We seek to further reinforce a safety-first mindset by linking employees’ compensation to safety performance through our AIP. Offshore employees are eligible to receive an additional quarterly safety bonus based on safety results at our offshore facilities.

Recruitment, Development and Leadership Training — We seek to recruit top talent through online recruiting platforms, referrals, university and college fairs, internships and professional recruiters. 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. We also offer leadership programs and continuing education opportunities to further develop employee skills.

Compensation and Benefits — Our success is based on financial performance and operational results, and we believe the structure of our compensation program is an important driver of these goals. Our compensation 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 have a bonus opportunity under the AIP, which is tied to Company performance on various financial, operational, safety, environmental and strategic goals, as well as personal performance. 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 18, 2025 for further information on our executive compensation program and philosophy.

Another objective of our employee programs is to provide comprehensive and competitive benefits designed to attract, retain, and support a successful workforce necessary to achieve our business strategy. Such benefits include retirement savings contributions, health and wellness initiatives, mental health resources, an on-site clinic for corporate employees, and flexible work arrangements as well as 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. Through these programs, we strive to give employees the tools and resources they need to succeed both professionally and personally and to foster a safe and collaborative work environment designed to help ensure that our employees stay resilient, healthy and productive.

Social Investment — We support a culture of stewardship through active corporate philanthropic efforts, community outreach programs, and fundraising efforts to benefit charitable organizations which contribute to the communities in which our employees work and live. 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

We face risks in the normal course of business and through global, regional and local events that could have an adverse impact on our operations and financial performance. The following are some important risk factors that could cause our actual results to differ materially from those projected in any forward-looking statements. If any of the events or circumstances described in any of the following risk factors occurs, our business, results of operations and/or financial condition, as well as the trading price of our common stock and future prospects, could be materially and adversely affected, and our actual results may differ materially from those contemplated in any forward-looking statements we make in any public disclosures.

These risks reflect the Company's beliefs and opinions as to factors that could materially and adversely affect the Company and its securities in the future. References to past events are provided by way of example only and are not intended to be a complete listing or representation as to whether or not such factors have occurred in the past or their likelihood of occurring in the future. 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.

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

Oil and natural gas prices are volatile and prolonged price declines could materially adversely affect our business, financial condition, results of operations, cash flows, access to capital, and our ability to replace and grow future production.

Among the most significant variable factors impacting our business and financial condition are the sales prices for crude oil and natural gas that we produce.

Prices we receive for our oil and natural gas depend on numerous factors beyond our control, including, among others:

- domestic and global supply of and demand for oil and natural gas;
- market uncertainty and consumer demand levels;
- weather and natural disasters such as hurricanes and other adverse climatic conditions;
- market differentials, including quality, transportation fees, tariffs, energy content and regional pricing;
- domestic and foreign governmental actions, regulations and taxes;
- prices and availability of alternative fuels and competing energy sources;
- political instability and economic conditions in key producing regions such as the Middle East, Russia, South America, Mexico, Africa and Europe;
- armed conflicts and hostilities such as the war in Ukraine and conflicts in Israel and the Middle East;
- public health events such as epidemics or pandemics;
- actions by OPEC Plus and other major producers and governments regarding production and pricing;
- political, legal and regulatory instability in regions we currently or in the future may operate, including any prolonged government shutdowns or lapses in appropriations that could disrupt our operations and future drilling plans and opportunities;
- trade restrictions, tariffs, trade barriers, price and exchange controls;
- oil and natural gas import and export levels and prices;
- global oil and natural gas exploration, production and inventory levels;
- local supply and demand fundamentals and transportation availability;
- infrastructure constraints in processing, gathering, storage and transportation;
- speculative trading in oil and natural gas futures;
- competing supply availability and prices of oil and natural gas;
- technological advances affecting energy consumption; and
- global economic conditions.

Given these various variables, commodity prices are inherently unpredictable. Historically, the markets for oil, natural gas and NGLs have been volatile and remained so during 2025 due in part to geopolitical tensions, the global economy, demand fluctuations, oversupply and macroeconomic uncertainty. As such, prices have been, and may continue to be, subject to wide fluctuations. For example, during the period January 1, 2025 through December 31, 2025, the monthly NYMEX WTI crude oil price per Bbl ranged from a low of $57.97 to a high of $75.74, and the monthly NYMEX Henry Hub natural gas price per MMBtu ranged from a low of $2.91 to a high of $4.26.

The majority of our sales are based on the spot market 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 75%, 19%, and 6%, respectively, of our estimated proved reserves as of December 31, 2025, and approximately 70%, 22%, and 8%, respectively, of our 2025 production on a Boe basis, our financial results are particularly sensitive to price movements in these commodities.

Sustained lower oil and natural gas prices adversely affect the Company in several ways:

- Lower sales value for our production reduces cash flows and net income.
- Lower cash flows may cause us to reduce our capital expenditure program, thereby potentially restricting our ability to replace and grow production and add proved reserves.
- Lower oil and natural gas prices could lead to write-downs and impairment charges in future periods, therefore reducing the carrying value of our assets and negatively impacting net income.
- Low prices could make a portion of our proved reserves uneconomic, which in turn could lead to the removal of certain of our year-end reported proved oil reserves in future periods. These reserve reductions could be significant.
- Lower oil and natural gas prices could lead to an inability to access, renew, or replace our credit facilities, impact our borrowing capacity under our credit facilities, and could also impair access to other sources of funding, potentially negatively impacting our liquidity.
- Lower prices could impair our ability to effect share repurchases because of lower cash flows.

If we are unable to replace oil and natural gas reserves, we may not be able to sustain or grow our business.

Our success depends largely upon our ability to find, develop or acquire additional economically recoverable reserves to replace or grow our proved reserves and maintain a portfolio of opportunities for future reserve additions and production over the long-term. Production from existing producing reserves naturally declines over time, requiring perpetual replacement of reserves to maintain or grow production. Our offshore E&P projects require significant upfront capital investment and extended lead times between initial discovery, project sanction and the commencement of production. As a result, changes in commodity prices, costs, market conditions or capital availability during development may negatively impact our ability to complete such projects as planned or to achieve expected returns, which could delay or reduce the addition of new reserves and production. Further, our need to generate revenues to fund operations, contribute to decommissioning activities and collateral obligations, and/or repay debt may also limit our ability to slow or shut-in production during periods of low commodity prices, which may further deplete our reserves during periods where adding reserves is uneconomical.

Exploring for, developing or acquiring reserves is highly capital intensive and uncertain. We cannot assure you that our future exploration, development or acquisition activities will result in additional proved reserves or that we will drill productive wells at acceptable costs. We may be unable to economically find, develop or acquire new reserves, particularly if our operating cash flows decline or capital becomes limited. Current market conditions could further limit financing availability, reduce acquisition opportunities, and/or further depress asset values and 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. Costs of drilling, completion and operation are often unpredictable, and operations may be curtailed, delayed or canceled due to various factors, including:

- unexpected drilling or formation conditions;
- equipment failures or accidents;
- inflation in exploration and drilling costs;
- fires, explosions, blowouts or surface cratering;
- lack of infrastructure or transportation access;
- labor shortages; and
- delays or shortages of services or equipment.

Our current operations are primarily concentrated in a single geographic region, making us vulnerable to regional risks.

Our production, revenue, reserves, and operating cash flows are derived primarily from properties in the Gulf of America. As a result, we are disproportionately exposed to regional risks such as:

- natural disasters and severe weather, such as hurricanes, winter storms, loop currents, and other adverse climatic conditions;
- changes in state or regional laws and regulations, including those imposing strict liability for pollution or requiring significant financial assurance for decommissioning;
- local price fluctuations, and gathering, pipeline, transportation and storage capacity limitations;
- production delays or regional production issues;
- limited customer base;
- infrastructure availability, including rigs, equipment, pipelines, oil field services, supplies and labor;
- access to, capacity and availability of pipelines, transportation, and/or gathering or processing that we depend on for marketing our production;
- financial assurance requirements for decommissioning obligations; and/or
- changes in laws, regulations, administration policies or court-ordered requirements that restrict or delay offshore leasing, permitting, site development or operation in federal waters where we operate.

These risks may be heightened by current geopolitical relations among Mexico, Canada and the U.S. Because most of our production is currently from properties located in the Gulf of America, adverse regional events could have a greater impact on our results of operations than on producers with more geographically diverse assets.

Global geopolitical tensions may increase volatility in oil, gas and NGL prices and could adversely affect our business.

Our oil and gas activities are affected by geopolitical and economic conditions that can cause energy market disruptions and price volatility. These include changes in energy policies, expropriation, contract cancellations or modifications, changes in laws and policies governing operations of foreign-based companies, changes in tax or royalty regimes, trade restrictions, currency fluctuations, terrorism, piracy, sanctions and armed conflicts.

Recent and ongoing geopolitical events illustrate these risks.

- Mexico and Canada: Political transitions following elections in 2024–2025 and continuing tension could lead to policy shifts or trade restrictions with the United States that affect the energy industry and broader economy.
- Russia and Ukraine: Russia's 2022 invasion of Ukraine has led to sweeping international sanctions and countermeasures that continue to disrupt global trade and financial markets. Additional sanctions or retaliatory actions could further affect the global economy and commodity markets. A cessation of hostilities or easing of sanctions could also cause commodity prices to decline, reducing our revenues.
- Israel and the Middle East: Ongoing hostilities in Israel and the Middle East have created and may continue to create additional regional instability and supply risks.

- Venezuela: Recent U.S. intervention in Venezuela could result in associated repercussions to supply of and demand for oil and natural gas and the economy generally.

These conflicts, and any escalation or additional geopolitical crises, could result in significant volatility in energy prices, supply disruptions, and broader economic instability. We continue to monitor these and future developments, but their duration and impact are unpredictable. Any of these factors, as well as other geopolitical tensions, could adversely affect our business, financial condition, or results of operations.

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

Our estimates of oil and natural gas reserves are based on judgments and assumptions about prices, costs, capital expenditures, and future production, and complex geological, geophysical, engineering and economic data. Changes in these assumptions, or differences between our interpretations and those of third-parties or regulators, can cause reserve estimates to vary significantly.

Actual production, oil and natural gas prices, costs, revenues, taxes, expenses and recoverable reserves may differ from estimates and could materially affect the quantity and value of our reserves. Our reserves may also be affected by production from adjacent properties operated by others. We regularly revise our estimates to reflect new data, production history, results of exploration and development, changes in prices, and production results. See Part I, Items 1 and 2. Business and Properties—Summary of Reserves for further discussion on 2025 changes in estimates of our proved reserves.

PV-10 is calculated using the pricing requirements established by the SEC, except it does not include estimated future income taxes, and does not necessarily represent the market value of our proved reserves. Actual future prices and costs used in computing PV-10 may be materially higher or lower. Further, actual future net revenues are affected by factors such as:

- capital expenditures and decommissioning costs;
- the rate and timing of production;
- changes in laws, regulations or taxes;
- volume, pricing and duration of our hedging contracts;
- market supply and demand for oil and natural gas;
- 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 our 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.

As of December 31, 2025, approximately 22% of our proved reserves were undeveloped and 19% were non-producing. Development of these reserves requires significant capital investment and successful drilling. Actual costs or results may differ from our estimates, and some reserves may not be produced within planned timeframes or at all. Any material inaccuracy in our reserve estimates or related assumptions could adversely affect our business, financial condition, and results of operations.

Our future asset retirement obligations, including plugging and abandonment expenditures and decommissioning costs, are difficult to predict, may vary significantly from period to period and could materially adversely affect our current and future financial results.

We record a liability for the discounted present value of our asset retirement obligations, including plugging wells, removing platforms, pipelines and facilities, and restoring sites at the end of operations. As of December 31, 2025, our short-term asset retirement obligation was $112.5 million and the long-term asset retirement obligation was $1,219.6 million. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* and Note 9 — *Asset Retirement Obligations* for more information.

We have divested properties where buyers assumed abandonment obligations; however, if those parties cannot perform, we could be held jointly and severally liable for further decommissioning costs under laws such as the OCSLA. Furthermore, if non-operating partners fail to pay their share of abandonment costs, we may be required to cover those amounts. As of December 31, 2025, we have accrued $0.5 million and $21.7 million in decommissioning 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.

Offshore obligations are typically more costly than onshore due to logistical challenges and stricter regulations. These estimates can change significantly due to regulatory changes, evolving technology, and the timing of abandonment, which often occurs many years in the future. As a result, we may be required to significantly increase or decrease our estimated asset retirement obligations and decommissioning expenses in future periods.

Events such as hurricanes or other natural disasters can also increase costs dramatically if platforms or facilities are damaged or not structurally intact. 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. Accordingly, our estimates of future asset retirement obligations and/or decommissioning costs could differ dramatically from what we may ultimately incur as a result of damage from a hurricane or other natural disaster.

Any unexpected increase in asset retirement obligations and/or decommissioning costs could materially and adversely affect our financial position and results of operations.

We risk losing leases if we cannot drill before such leases expire.

Our leases may expire unless production is established as required by leases covering undeveloped acres. If commodity prices remain low for an extended period of time, drilling might not be economical, and some leases could expire, which could have an adverse effect on our business. As of December 31, 2025, approximately 46% of our net acreage was undeveloped. See Part I, Items 1 and 2. Business and Properties—Acreage for further discussion.

Our development plans for areas not held by production are subject to change based upon various factors. Many of these factors are beyond our control, including drilling results, oil and natural gas prices, access to capital, drilling and production costs, service and equipment availability, gathering system and pipeline transportation constraints and regulatory approvals. For acreage we do not operate, we have even less control over development plans, increasing the risk of expiration.

We depend on infrastructure to market and deliver our production.

Our ability to sell our production relies in part on access to sufficient critical infrastructure, including gathering systems, pipelines, transportation, and processing facilities. If this infrastructure lacks capacity, is unavailable, or is shut down due to maintenance, weather, regulatory restrictions, legal or public opinion challenges, or other issues, we may have to shut in wells, facilities or delay development.

Inflation and interest rate changes could increase our costs.

Rising inflation and associated changes in monetary policy, including interest rates, may increase the cost of our goods, services and labor, which raises our capital expenditures and operating costs. Higher interest rates may also increase the cost of capital and slow economic growth, negatively affecting our business. Inflationary pressures continued to ease through late 2025, with annual U.S. inflation ending the year at approximately 2.7%. The U.S. Federal Reserve (the "Federal Reserve") implemented three consecutive interest rate cuts in September, October, and December 2025, ultimately lowering the federal funds target range to 3.50%–3.75% by year-end, down from the two-decade highs maintained earlier in the year. Although inflation remains above the Fed's 2% goal, policymakers signaled caution due to persistent price pressures and a softening labor market, leaving uncertainty around the pace and timing of any additional rate cuts in 2026. Continued inflation and volatile energy prices may further increase the cost of goods, services, and labor, driving up operating expenses and capital spending. We cannot predict future inflation or monetary policy trends.

We may not be able to obtain sufficient surety bonds on reasonably acceptable terms to conduct our business.

The offshore surety bond market has undergone a structural shift driven largely by adverse developments in restructurings and bankruptcies of companies operating in the OCS, leading to materially reduced availability of surety bonds as a number of surety companies have exited the offshore surety market. In addition, remaining surety companies generally have a lower risk tolerance which has increased pressure to provide collateral on existing and new surety bonds. As a result, new surety 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, if surety market conditions continue to tighten, 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 and grow our operations in the region.

In November 2025, we entered into various collateral and security arrangements with our surety bond providers to limit the amount of collateral we are required to provide on existing surety bonds through 2031. In return for our agreement to post annual collateral commitments and make minimum plugging and abandonment expenditures, our surety providers agreed not to require additional collateral under their existing surety agreements above the agreed upon amounts, draw on letters of credit posted for the sureties' benefit, or cancel any existing surety bonds. The arrangements generally contain certain events of default which, if triggered and not cured by us within the cure period, would terminate the standstill period and provide the sureties their full rights under their respective surety and indemnity agreements, including the right to call collateral. Events of default include, but are not limited to, the failure to maintain liquidity of $200.0 million or above a specified credit rating. Please see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies* for further information about these arrangements, our collateral funding requirements and plugging and abandonment commitments. New surety bonds are not subject to these collateral limits, and we may therefore have to post increased collateral on new bonds.

BOEM also requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances, such as surety bonds, to meet lease obligations, including decommissioning activities on the OCS. In 2024, BOEM adopted a new financial assurance rule that significantly increased supplemental bonding requirements for certain lessees and grant holders conducting operations in the OCS. The final rule was challenged in court by multiple oil and gas industry groups and the states of Mississippi, Louisiana and Texas. The U.S. District Court for the Western District of Louisiana granted a stay of the litigation while the agency pursues efforts to suspend, revise, or rescind the final rule. The court's order temporarily limits full implementation of the final rule by limiting BOEM's ability to seek supplemental financial assurance to cases of sole liability properties and certain non-sole liability properties that are held by owners who are not financially strong, as described in the final rule, and that have no co-owners or predecessors who are financially strong.

In May 2025, the DOI announced its intent to revise and develop a new rule that is consistent with the Trump Administration's 2020 proposed rule on financial assurance. Although the specific substance and timing of a revised rule cannot be predicted at this time, it is anticipated that the new revised rule will revert to BOEM's former policy of considering the financial strength of both co-owners and predecessors in title when determining whether supplemental financial assurance is required. Notwithstanding the status of the final rule or a new revised rule, BOEM has stated it will continue to require lessees on the OCS to provide financial assurance in instances where BOEM determines there is a substantial risk of nonperformance of their decommissioning liabilities. Despite expected changes to the BOEM financial assurance rule, we remain subject to existing bonding requirements, and future rules are uncertain. In the future, BOEM could implement new or revised rules that require additional financial assurances in material amounts. BOEM may reject proposals to satisfy any such additional financial assurance coverage and make demands that exceed our capabilities or the availability of surety bonds in the market on acceptable commercial terms. If we cannot provide required assurances on acceptable terms, BOEM could impose penalties, suspend operations, or cancel leases. Surety companies may also demand additional collateral on future surety bonds, which could reduce our liquidity and limit future capital spending. Market conditions and regulatory changes could continue to further affect the availability and costs of future surety bonds, materially impacting our ability to operate on the OCS. After 2031, under our existing and future indemnity agreements, surety companies have the right to demand additional collateral to support currently existing bonds. We cannot provide assurance that we will be able to satisfy future collateral demands. Collateral in the form of cash or letters of credit would negatively impact our liquidity position, 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.

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.

Technology and cybersecurity threats could disrupt our operations and cause reputational and financial harm to our business.

As an exploration and production company, we rely heavily on information and operational technology systems to support our exploration, production, and administrative functions across our offshore and corporate operations. The energy sector's growing reliance on information and operational technology to manage critical business functions has significantly increased the exposure to cybersecurity threats. As such, our systems face increasing technological and cybersecurity threats which could result in unauthorized access to sensitive information or render our systems unusable. For example, a cyber-attack on a production control system could result in significant environmental and safety risks, such as a well incident, shut-in or spill that could cause business interruption, reputational damage, regulatory fines or penalties, costs of compliance or remediation or insurance limitations. Other examples of cybersecurity threats we may 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 also face similar cybersecurity threats, which may impact us. We rely on third-party vendors and service providers, including, but not limited to, software and hardware suppliers, cloud-based service providers, and industrial equipment manufacturers, which may present additional cybersecurity risks to us beyond our direct control if their systems or supply chains are compromised. Any successful cyber breach, whether of our systems or those of a third-party provider, could compromise our systems, disrupt our operations, or result in the unauthorized disclosure of sensitive information and/or infrastructure or environmental damage. Such incidents could result in regulatory investigations, litigation, fines and penalties, reputational damage, and significant costs for compliance, remediation and system restoration.

Although we maintain risk-based security programs integrated with enterprise risk management, which include, but are not limited to, cybersecurity oversight, detection and response processes, third-party risk management, and cyber incident insurance, these measures may not prevent or fully cover losses. Attack techniques continue to evolve, and some breaches may go undetected for extended periods. Breaches of our information and operational technology systems, or any material outage or data compromise could materially affect our operations, and financial condition, damage our reputation, lead to financial losses from remedial actions, loss of business, and potential liability, and impact our ability to meet regulatory obligations.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As of December 31, 2025, approximately 19% of our production is from properties we do not operate. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such properties to fund their contractual share of the capital and operating expenditures. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on such properties during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these properties could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

Hedging transactions may limit our potential gains and expose us to other risks.

We use hedging transactions, such as futures contracts on the NYMEX, to manage price volatility for oil, natural gas, and NGLs. While these arrangements help reduce downside risk, they can also limit potential gains if prices rise above hedge levels. In certain circumstances, such transactions may expose us to the risk of financial loss, including instances in which:

- our production is less than expected or is shut-in for extended periods;
- there is a widening of price differentials between delivery points;
- the counterparties default;
- there are unexpected market events which materially impact oil or natural gas prices; or
- we are unable to market our production as planned.

Future collateral requirements depend on market conditions. These factors could increase costs or liquidity needs and negatively affect our financial results.

Compliance with environmental laws, including legal requirements related to marine life and endangered and threatened species, could increase our costs and limit operations.

Our offshore operations are subject to stringent federal, state and/or local environmental laws and regulations governing emissions, waste disposal and the protection of marine life and endangered species. These regulations require permits, restrict or prohibit certain activities within protected areas or that may affect certain wildlife, including marine species and endangered and threatened species and impose substantial liabilities for pollution. Additionally, the threat of climate change has, in recent years, been a heightened area of litigation, regulations and disclosure requirements in the United States. Although federal efforts seeking to mandate climate-related disclosures have not been successful, many other environmental requirements remain in place, and future changes to environmental restrictions and regulations remain uncertain. Further, states and other jurisdictions may impose stricter standards in the future. Any legal developments that increase compliance costs or restrict drilling could have a material adverse effect on our business, results of operations and financial condition. 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.

Regulatory changes could restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to leases, which could have a material adverse effect on our business, financial condition or results of operations.

Our industry and oil and gas operations are subject to numerous U.S. federal, state and local laws. These regulations govern all aspects of our operations, including permits, environmental protections, emissions, drilling plans, transportation and service infrastructure, bonding for decommissioning, reporting and taxation related to our 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 prior U.S. presidential administrations. For example, over the past decade, BSEE and BOEM have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Effective October 2023, BSEE published a final rule requiring, among other things, that a blowout preventer system is able to close and seal the wellbore at all times to the well’s maximum kick tolerance design limits and more stringent requirements for failure reporting. The current presidential administration has stated its intent to reduce various regulatory burdens for fossil fuel projects although future regulations may vary under various political leadership. In Mexico, recent energy reforms have strengthened state control and introduced new permitting and unitization procedures under SENER and the newly formed National Energy Commission (CNE).

Failure to comply with any regulations applicable to our operations can result in significant administrative, civil or criminal penalties, injunctions and other restrictions on our operations or reputational harm. In addition, because we hold federal leases, the U.S. federal government requires us to comply with numerous additional regulations applicable to government contractors. Future, more strict regulations, executive orders, or agency actions could restrict offshore leasing, delay projects, increase compliance costs, or limit access to drilling locations. Litigation challenging leasing programs and future federal policies under different political leadership add uncertainty. These changes could result in higher bonding requirements, penalties, or suspension of operations, which may materially affect our business and financial results. Also, if material spill incidents 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.

Production shut-ins could increase costs and reduce future production.

If we are forced to shut-in wells, restarting production may require significant expense and could make some wells uneconomic at low prices, 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, production levels may be lower than before, and we may need to permanently discontinue development plans or production. Any prolonged shut-in or curtailment could negatively affect our reserves, financial condition and results of operations.

Severe weather or public health events could disrupt production and reduce revenues.

We may experience significant shut-ins and losses of production due to events outside of our control, such as adverse weather conditions. As an offshore exploration and development company with significant assets in the U.S. Gulf of America, our operations are particularly vulnerable to hurricanes, tropical and winter storms, loop currents, and other adverse weather conditions in the region. Further, our operations could be disrupted by epidemics, outbreaks or other public health events such as in 2020 by Covid-19. A regional or global public health crisis could also disrupt operations by causing workforce shortages, supply chain interruptions, or government-imposed restrictions. Any prolonged disruption could materially affect our production, revenue, and financial condition.

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. For example, a 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 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 or retentions, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and we may experience production interruptions for which we do not have production interruption insurance. There is no assurance that our insurance 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.

We may also be liable for damages from an event relating to a project in which we own a non-operating working interest and over which we have limited control. Any event resulting in a significant interruption to our business, whether covered by insurance or not, could severely impact our financial position.

We reevaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain adequate insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage or self-insure. Further, we may not be able to secure additional insurance or financial assurance surety bonds that might be required by future governmental regulations. This may cause us to restrict our operations in the areas in which we operate, 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.

We periodically provide production forecasts and guidance based on assumptions about existing wells and anticipated operating conditions. Such forecasts do not reflect all possible impacts which are outside our control, such as unanticipated facility or equipment malfunctions, adverse weather effects outside budgeted expectations, adverse resolutions to disputes relating to operatorships, unanticipated regulatory and legal impacts, or significant declines in commodity prices or material increases in costs. If risks occur that significantly impact our operations and costs, actual production could be materially lower than anticipated, which may make certain production uneconomical and negatively effect our financial results.

Our strategy emphasizes Deepwater exploration and development, which involves significantly higher operational and financial risks than operations in shallower waters. Deepwater activities in the Gulf of America are complex, capital-intensive, and subject to a wide range of uncertainties.

We generally focus on Deepwater exploration and development, primarily in the Deepwater Gulf of America. Exploration for oil or natural gas in Deepwater regions, including the Gulf of America, generally involves greater operational and financial risks than exploration in the shallower waters and require advanced technology, specialized rigs, and extensive subsea infrastructure. Deepwater conditions increase the likelihood of technical challenges, including geological complexity, high temperatures and pressures, and other drilling risks. As a result, wells may experience operational obstacles, be non-commercial, may take longer to drill, or may not produce sufficient revenue to recover drilling and development costs.

Our operations are also subject to unexpected drilling conditions, equipment failures or accidents, extreme weather, labor and supply-chain shortages, and other operational delays. Limited infrastructure in Deepwater areas may extend the time between discovery and first production, and in some cases, may render discoveries uneconomic to develop. We may also pursue future exploration and development opportunities internationally, where similar Deepwater risks would apply.

Deepwater operations also carry significant environmental risks. Failure to manage inherent operational risks related to exploration, development, production and decommissioning can result in unexpected incidents, such as oil spills, explosions, mechanical failures, or loss of well control causing personal injury, loss of life, environmental damage, loss of revenues, legal liability and/or disruptions of operations. For example, an oil spill or substantial threat of discharge could result in strict liability for cleanup costs, natural resource damage, economic losses, and other penalties. Such events could materially and adversely affect our financial condition.

In addition, fluctuations in oil and natural gas prices affect both the demand for and cost of drilling rigs, equipment, and related services, which may further increase the overall cost and risk of Deepwater projects.

If any of these risks materialize, we could incur substantial losses, including property damage, environmental remediation costs, fatalities or serious injuries, regulatory investigations or penalties, prolonged operational downtime, and significant repair expenses. Any of these events could have a material adverse effect on our business, financial condition, and results of operations.

Intense industry competition could limit our growth and increase costs.

We operate in a highly competitive industry where many of our competitors are larger and have substantially greater financial resources. These companies may outbid us for leases and acquisitions, and have more capital to make acquisitions, enter into joint ventures, attract and retain skilled personnel, obtain equipment, and invest in advanced technologies. Such competition can significantly reduce our opportunities for growth, increase costs and limit our access to resources. In addition, larger, more diverse competitors with greater financial resources may be better able to respond and adapt to adverse economic and industry conditions, including price fluctuations, reduced demand, and current and future regulatory requirements and taxes. If we cannot compete effectively and economically, our revenues and growth prospects could be materially affected.

The loss of a significant customer could materially reduce our revenue and materially adversely affect our business.

We rely on a limited number of customers for a substantial portion of our revenue. The loss of any large customer, such as Shell Trading (US) Company, Exxon Mobil Corporation and Chevron Corporation, which represent 35%, 23% and 12% of our oil, natural gas and NGL revenues for the year ended December 31, 2025, respectively, 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.

We rely on skilled and experienced personnel, and shortages in such personnel, higher labor costs or the loss of key management could adversely affect our ability to operate.

Our offshore exploration, production and decommissioning activities rely on highly skilled, experienced, and technical personnel. The loss of key individuals or our inability to attract and retain skilled workers could negatively affect our productivity, profitability, and growth. Competition for specialized talent is intense in our industry, and labor costs may rise due to market conditions or unionization. These factors could impair our ability to operate effectively and economically. In addition, unanticipated changes in management turnover may impact our ability to effectively implement our strategy and manage our business.

We have various contractual commitments. Our failure to satisfy these commitments could adversely affect our results of operations and financial position.

Contracts customary in our industry may expose us to significant economic loss. We have entered into, and may in the future enter into, transportation and other commercial arrangements that include minimum volume commitments, which could expose us to significant contractual penalties and fees if our production declines and we cannot meet these commitments. As of December 31, 2025, our future minimum transportation fees totaled approximately $43.9 million through 2030. Failure to satisfy these commitments could reduce our cash flow from operations, which may require us to delay investments, reduce capital expenditures, or seek alternative financing. Similarly, we may enter into drilling rig and other certain vessel contracts that require significant financial commitments, have high operating and standby rates, and include significant penalties for termination. These outcomes could materially and adversely affect our results of operations and financial condition. 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 and our tax obligations and related filings are complex. In addition, changes in tax laws or their interpretation could increase our tax obligations and reduce after-tax profitability.

We are subject to income, withholding and other taxes in the United States on a worldwide basis and in various U.S. state and local and non-U.S. jurisdictions with respect to our income, operations and subsidiaries in those jurisdictions. 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. Our after-tax profitability depends on numerous factors, including the availability of tax deductions, credits, exemptions, refunds and other benefits to reduce our tax liabilities, the allocation of earnings among jurisdictions, and the treatment of intercompany transactions. We also may expand our operations into new jurisdictions which could subject us to additional significant tax liabilities.

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, U.S. federal and state legislation 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. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any changes could take effect. In addition, states in which we operate or own assets may also impose new or increased taxes or fees on oil and natural gas extraction. The passage of any such legislation or other future tax legislative or regulatory changes in the United States, Mexico or in any other jurisdiction in which we operate or have subsidiaries now or in the future could increase our future tax liabilities and adversely impact our after-tax profitability.

Our future tax liabilities may be greater than expected if our ability to use our net operating loss ("NOL") and interest expense carryforwards are limited, which may adversely affect our results of operations and cash flows.

As of December 31, 2025, we had approximately $139.3 million of U.S. federal tax-affected NOL carryforwards and $16.4 million of state tax-affected NOL carryforwards. Some of our 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, 2025, we also had $40.2 million of tax-affected U.S. federal and state interest expense carryforwards. Utilization of these NOL and interest expense carryforwards depends on various factors, including future taxable 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 a corporation can use to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382 of the Code). 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 a corporation's stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. Most 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 we were to undergo an ownership change in the future, utilization of our NOL and interest expense carryforwards would be subject to further limitation under Section 382 of the Code. Similar limitations apply under state income tax laws. Any unused annual limitation generally may be carried over to later taxable years. If we are unable to fully utilize these carryforwards, our future tax liabilities could be greater than expected, which may adversely affect our results of operations and cash flows.

Our Mexican operations are subject to evolving regulatory and environmental requirements that could increase costs and create compliance risks.

Through our ownership in Talos Mexico, we hold a non-operated interest in oil and gas properties in shallow waters off the coast of Tabasco, Mexico that are subject to regulation by SENER, ASEA and other Mexican authorities. The legal framework for the Mexican energy sector has undergone significant reform and continues to evolve. Future changes in laws, regulations, or administrative practices could impose new or more stringent requirements, increasing our operating costs or capital expenditures in the region.

See Part I, Items 1 and 2. Business and Properties — Government Regulation for additional disclosure relating to the legal requirements imposed by Mexican regulatory bodies to which we may be subject in the pursuit of our operations conducted through our equity method investment.

Additionally, under our Block 7 PSC, we are jointly and severally liable for all obligations under the PSC, including exploration, development, appraisal, extraction, abandonment and environmental compliance. Failure to meet these obligations could result in penalties or contractual rescission of the PSC. See Part I, Items 1 and 2. Business and Properties — Mexico for more information regarding our ownership interest in Talos Mexico.

We may also seek to expand our operations in offshore Mexico in the future, and any such expansion could subject us to additional operational, regulatory, tax, and political risks associated with conducting business in that region.

Seismic data interpretation does not guarantee the presence of commercially viable hydrocarbons.

We rely on three-dimensional seismic studies to evaluate drilling opportunities on our properties and potential acquisitions. These studies are interpretive tools and cannot ensure that hydrocarbons are present or, if present, that they can produce in economic quantities. Seismic indications of hydrocarbon saturation are generally not reliable indicators of productive reservoir rock. As a result, drilling based on seismic data may lead to unsuccessful drilling and operational results, which could adversely affect our operational results and financial condition.

Violation of anti-corruption laws, including the U.S. Foreign Corrupt Practices Act, could result in severe penalties and loss of key contracts.

We are subject to the U.S. Foreign Corrupt Practices Act (the "FCPA") and similar laws that prohibit improper payments or offers of payments to foreign officials and political parties to obtain or retain business. Operating in certain jurisdictions may expose us to demands from government officials or other parties in violation of the FCPA. Despite our compliance policies and training, we face the risk that employees or third-party representatives might engage in prohibited 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 could result in significant criminal or civil sanctions and allow CNH to rescind the PSC. Such event could materially and adversely affect our business, operating results and financial condition.

Our business faces risks related to climate change concerns that could increase our operating costs, restrict where we can operate, and reduce demand for the crude oil and natural gas that we produce.

Climate change continues to attract public, political and scientific attention both domestically and abroad. For example, the Inflation Reduction Act of 2022 (the "IRA 2022") contained 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, certain of these incentives and initiatives have been paused, repealed or otherwise modified due to the passage of the OBBBA. The IRA 2022 also imposed the first ever federal fee on the GHG emissions through a methane emissions charge, although the OBBBA postponed the implementation of the methane emissions charge until 2034.

These 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.

Additional federal, state, and local initiatives, including potential carbon taxes, cap-and-trade programs, mandatory GHG reporting, and rules that directly limit emissions, could further increase compliance costs or restrict development activities. International actions to regulate or limit GHG emissions may have similar effects. Climate-related political, financial, and litigation pressures on fossil fuel producers may also continue to grow. 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.

Future legislation or regulatory programs designed to reduce or eliminate GHG emissions may require us to install new emissions-control equipment, purchase emissions credits, or comply with additional reporting or operational requirements. These measures could increase the cost of consuming hydrocarbons and reduce demand for the oil and natural gas we produce. They may also cause us to delay, limit, or cancel projects or impair our ability to operate economically.

Any of these factors such as regulatory changes, increased compliance costs, reduced product demand, or climate-related operational constraints, could negatively affect our business, financial condition, and results of operations.

Evolving expectations, regulations and related scrutiny regarding environmental, social and governance matters could impact our business and stock price.

In past years, there has been increased attention to climate change and societal expectations on companies to address climate change and substitute energy sources for fossil fuels. Although recent U.S. political trends have shifted away from certain environmental, social and governance initiatives, these matters remain highly relevant to our future strategy and business. Future shifts in investor priorities, regulatory requirements, or societal expectations could increase costs, limit demand for our products, reduce profits, or affect access to capital, which could negatively impact our stock price.

While we endeavor to publish transparent sustainability reports, the voluntary disclosures in these reports rely on assumptions and estimates or hypothetical scenarios that may not reflect actual outcomes, and they are increasingly subject to scrutiny for accuracy and potential "greenwashing." Regulators, investors, and other stakeholders may challenge our statements or goals, which could lead to investigations, litigation, reputational harm, and additional compliance costs. Certain regulators, such as the SEC and various state agencies, as well as non-governmental organizations and other private sector actors have also filed lawsuits under various securities and consumer protection laws alleging that certain statements related to environmental, social or governance goals or commitments were misleading, false, or otherwise deceptive. Certain employment or business 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. The complex regulatory and legal frameworks applicable to such initiatives continue to evolve.

In addition, organizations that provide information, ratings or proxy advisory services to investors on corporate governance and related matters have developed processes for evaluating companies on their approach to environmental, social and governance initiatives. Such ratings or recommendations and reports are used by some investors to inform their investment and voting decisions. Unfavorable ratings or recommendations 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. We may also face criticism or legal challenges from parties proposing or opposed to environmental, social and governance initiatives, including claims that our environmental or social commitments are inconsistent with evolving laws. These risks could disrupt operations, increase expenses, and negatively affect our stock price and ability to attract customers, employees, and investors.

Changes in U.S. trade policy, including tariffs or other restrictions, could increase costs and adversely affect our business.

There has been continued uncertainty about U.S. trade policies, treaties, tariffs, taxes, and other limitations that could impact our costs and supply chain. Such tariffs and any additional tariffs, trade barriers, or retaliatory measures could further increase the cost of materials and services we use, disrupt our supply chain, and negatively affect our business, prospects, financial condition and operating results.

We may not realize expected benefits from future acquisitions, and integration challenges could harm our business.

Our growth strategy includes pursuing acquisitions. However, we may not achieve anticipated benefits such as increased earnings, cost savings, operational efficiencies, or reserve additions. Challenges may include higher-than-expected costs, inaccurate reserve estimates, unknown liabilities, challenges operating in new geographic regions and under new regulatory frameworks, and difficulties integrating operations, systems, corporate functions, and personnel. In addition, integrating acquired assets can increase indebtedness, divert management's focus, and involve difficulties associated with operating a larger or geographically diverse organization. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results. If we cannot successfully integrate acquired businesses or realize expected benefits, our business, financial condition, and results of operations could be adversely affected.

Acquisitions and current assets expose us to potentially significant liabilities, including abandonment obligations.

We evaluate factors such as reserve estimates, the timing of recovering reserves, exploration potential, future prices, operating costs and potential environmental and regulatory liabilities, including P&A liabilities and decommissioning obligations when leasing or acquiring oil and gas properties. These assessments are inherently uncertain and may not identify all issues. Reviews may miss defects or liabilities, and we may acquire properties on an "as-is" basis with limited contractual protections.

We may face claims related to environmental, title, regulatory, tax, contract, litigation or other matters that were unknown at the time of acquisition. While we may be able to obtain indemnities for certain pre-closing liabilities, these protections are typically limited in scope and duration and often are insufficient to cover the full liability. If sellers or other parties fail to meet their obligations, we could be responsible for significant costs, which could materially and adversely affect our operations, financial condition, and results.

Litigation outcomes could materially affect our financial condition.

We may be involved in legal proceedings, and an unfavorable resolution could have a material impact on our financial position and results of operations. If potential liabilities are not fully covered by insurance, or if coverage is inadequate, we could incur significant losses. See Part I, Item 3. Legal Proceedings for more information.

Lower oil and natural gas prices and other factors have resulted in, and may in the future result in additional, ceiling test impairments and other impairments of our asset carrying values.

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the costs to acquire, explore for and develop oil and gas properties. Under the full cost method of accounting, our 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 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Impairment of oil and natural gas properties" on the consolidated statements of operations and an increase to "Accumulated depreciation, depletion and amortization" on our consolidated balance sheets. An impairment of oil and gas properties does not impact cash flows from operating activities, but does reduce net income. The risk that we are required to impair the carrying value of oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, impairments 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 impairments of our oil and natural gas properties and other assets in the future, and incur additional charges against future earnings. For the year ended December 31, 2025, the Company recorded an impairment of $454.5 million. Any required impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

A prolonged government shutdown or lapse in federal appropriations could disrupt our offshore operations and delay required regulatory approvals.

From time to time, the U.S. federal government has experienced periods of prolonged shutdowns. A prolonged government shutdown, lapse in federal appropriations or other resulting restrictions on federal agency operations could result in significant delays or interruptions in future federal lease sales, permitting, inspections, approvals, decommissioning plans, and other agency actions (including actions by BOEM, BSEE, US. Coast Guard) upon which our offshore exploration, development and production activities in the U.S. Gulf of America depend. Such delays could increase project timelines, cause suspension or postponement of planned drilling plans, completion, tie-ins or platform work, and could decrease production, postpone capital projects, increase other costs or delay revenues, which could have a material adverse effect on our business, results of operations and cash flows.

In addition, a government shutdown could affect supply-chain timing and create macroeconomic uncertainty that affects commodity markets and project financing which could materially adversely affect our financial condition, liquidity and results of operations.

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 identified two material weaknesses. 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 our Annual Report on Form 10-K for the year ended December 31, 2024. The Audit Committee did not identify any related material errors in the Company's historical financial statements.

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 related covenants in our current or future credit agreement and indentures could restrict our operations, and failure to comply with the covenants could result in accelerated payment obligations.

The agreements governing our debt may impose significant restrictions limiting our ability to take certain actions, including:

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

These restrictions reduce our financial flexibility and may limit our ability to respond to changing business conditions or pursue growth opportunities. Our debt obligations require substantial cash flow for interest and principal payments, which reduces funds available for operations, capital expenditures, and other business needs. In addition, high levels of outstanding debt may:

- limit our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detract from our ability to successfully withstand a downturn in our business or the economy generally; and
- place us at a competitive disadvantage against other less leveraged competitors.

In addition, borrowings under our Bank Credit Facility bear interest at variable rates, making us sensitive to rate increases. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — Debt for additional information on the Bank Credit Facility and Senior Notes.

If we fail to comply with covenants and other restrictions in our debt agreements, including financial ratio requirements, it could result in an event of default and the acceleration of repayment. Our ability to comply with covenants and other restrictions may be affected by events beyond our control, including 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 A&R Credit Agreement for a portion of our future capital needs. Our borrowing base under the new credit facility is subject to semi-annual redetermination based on proved reserves. Such borrowing base determines the amount which is available under the facility. If 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 deficiency or take other corrective actions. Specifically, we are allowed to cure a borrowing base deficiency by: (i) repaying amounts outstanding sufficient to cure the borrowing base deficiency within 30 days; (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 cash flows from operating activities to meet our debt obligations. If we do not have sufficient cash to repay our indebtedness, 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. However, our A&R Credit Agreement and indentures may prohibit us from taking such actions, and we may not be able to refinance or restructure our indebtedness on acceptable terms, and any refinancing could involve higher interest rates and more restrictive covenants. In addition, financial market conditions, our market value, and operating performance may limit our ability to conduct equity offerings, refinance our debt or sell assets.

The Carlos Slim family's significant ownership and voting power may create conflicts of interest and influence shareholder votes and major strategic decisions.

As of December 31, 2025, Control Empresarial de Capitales, S.A. de C.V. ("Control Empresarial"), an entity controlled by the family of Carlos Slim Helú (collectively, the "Slim Family") beneficially owned and possessed voting power of approximately 25.8% of our outstanding common stock. This ownership gives the Slim Family significant influence over matters requiring stockholder approval, including changes in capital structure, mergers or acquisitions, and corporate governance. Their interests may differ from those of other stockholders, and they may make decisions that are adverse to other stockholders' interests.

This concentration of voting power could influence a sale of our company and may discourage third parties from seeking to acquire our common stock which could negatively impact the market price of our common stock. Although we and affiliates of the Slim Family have extended the standstill arrangement through December 16, 2026, the agreement does not restrict voting rights or other actions. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Related Party Transactions* for additional information on the cooperation agreement with Control Empresarial.

A financial crisis or disruption in credit markets could limit our access to funding and adversely impact our ability to do business.

We fund our operations and capital expenditures primarily through cash flow from operations and borrowings under our bank credit facility. We may also seek funding from capital markets or asset sales for additional liquidity. A financial crisis or market disruption could reduce our ability to access these sources of funding. For example, our borrowing capacity under our bank credit facility could be limited by a borrowing base reduction, availability cap, financial covenant breach, or lender non-performance.

Broader market instability could also restrict access to debt and equity markets, increase counterparty credit risk, and require us to post additional collateral under certain agreements. If we cannot obtain adequate financing, we may need to delay investments, sell assets, or seek alternative funding on unfavorable terms, any of which could materially affect our financial condition and results of operations.

From time to time, we may retire or repurchase outstanding debt through cash payments, exchanges for equity or debt, or other transactions, depending on market conditions, liquidity needs, and contractual restrictions. These transactions could be material and may result in taxable cancellation of indebtedness income or limit our ability to deduct future interest expenses, which could create current or future tax liabilities and adversely impact our ability to deduct interest expenses in the future. This could result in a current or future tax liability and could adversely affect our financial condition and cash flows.

We require substantial capital to fund our operations and replace our production and may not be able to obtain financing on acceptable terms.

Our business requires substantial capital for acquiring, developing, and producing oil and natural gas reserves. We fund these expenditures primarily through operating cash flow, cash on hand, and borrowings under our A&R Credit Agreement. The amount and timing of future spending depend on factors beyond our control, including commodity prices, drilling results, service, infrastructure and equipment availability, and regulatory, technological and competitive developments.

If oil and natural gas prices decline or other factors reduce our cash flow or borrowing capacity, we may be unable to fund planned projects. In that case, we may need to raise additional debt or equity or sell assets, and we cannot assure you that such financing will be available on favorable terms, or at all. Limited access to capital could reduce our ability to replace reserves and grow production, which may adversely affect our business and financial condition.

As a holding company, we depend on distributions from Talos Production Inc. and our subsidiaries to meet our obligations.

We are a holding company that has no material assets other than our ownership of Talos Production Inc. We have no independent source of revenue. We rely on cash distributions from Talos Production Inc. to pay taxes, cover corporate expenses, and, if declared, pay dividends on our common stock. Although we do not expect to pay dividends on our common stock in the near term, if our Board of Directors decides to do so in the future, our ability to pay dividends will depend on Talos Production Inc.'s ability to make distributions to us, which is subject to restrictions under its debt agreements and applicable law. If Talos Production Inc. is unable to make distributions, our liquidity and financial condition could be materially adversely affected. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt — Limitation on Restricted Payments Including Dividends* for additional information.

Our charter allows certain directors and stockholders to pursue business opportunities that may not be offered to us.

Subject to the limitations of applicable law, our charter permits directors and officers affiliated with principal stockholders to engage in activities that may compete with us and to pursue business opportunities without offering them to us. These provisions also allow transactions between us and entities in which our directors or officers have an interest. Specifically, our Second Amended and Restated Certificate of Incorporation:

- 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.

Currently, none of our directors or officers are affiliated with a Principal Stockholder. However, these provisions create the possibility that business opportunities that might otherwise be available to us could be directed to other parties, which may limit our ability to pursue certain transactions and could adversely affect our growth prospects.

Our charter includes exclusive forum provisions that may limit stockholder's ability to choose a judicial forum for disputes.

Our Second Amended and Restated Certificate of Incorporation provides that, unless we consent otherwise, certain claims, including derivative actions, fiduciary duty claims, and matters governed by Delaware law, must be brought in the Delaware Court of Chancery. It also designates U.S. federal district courts as the exclusive forum for Securities Act claims, subject to enforceability under Delaware law. These provisions do not apply to claims under the Exchange Act, which must be brought in federal court. These forum provisions may limit a stockholder's ability to bring a claim in a forum they find favorable and could discourage lawsuits.

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. If a court determines these provisions are unenforceable, we could incur additional costs defending actions in multiple jurisdictions, which may adversely affect our business and financial condition.

Future sales, or the perception of future sales, of our stock could lower our share price and dilute the holdings of our existing stockholders.

Sales of a substantial number of shares, or even the expectation of a future sale, could reduce our stock price and make it harder for us to raise capital on favorable terms. If these shares are sold, or if investors believe they will be sold, our stock price could decline. We may also issue additional shares in the future to raise capital or fund acquisitions. Any such issuance could significantly increase the number of shares outstanding, dilute current stockholders' voting power, and negatively affect our stock price.

Stockholder activism could disrupt our business and harm our stock price.

We may face actions or proposals from activist stockholders that conflict with our business strategy or other stockholders' interests. Responding to these activities can be costly, time-consuming, and distract management and the Board from running the business. Activism may also create uncertainty about our future direction, which could harm relationships with customers, suppliers, and employees, and make it harder to attract talent. If a proxy contest occurs, we could incur significant legal and solicitation expenses and management attention could be diverted. Activist campaigns may also lead to litigation, further increasing costs and disruption. These activities could negatively affect our ability to execute our strategic plan and cause our stock price to fluctuate. 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.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Assessing, Identifying and Managing Cybersecurity Risks — We rely extensively on information technology ("IT") and operational technology ("OT") systems to support exploration, drilling, production, and administrative functions across our offshore and corporate operations. These systems include process control systems on production platforms, remote monitoring systems, and enterprise IT applications for finance, human resources, and supply chain management. Our cybersecurity program is designed to protect these systems from unauthorized access, data breaches, ransomware, and other cyber threats. We aim to implement industry-standard security measures including network segmentation, firewalls, intrusion detection, endpoint protection, multi-factor authentication, incident response plans, security awareness training, and regular security audits. In addition, we maintain policies and procedures designed to assess, identify and manage cybersecurity threats and incidents and strive to align our cybersecurity operating model with the National Institute of Standards and Technology Cybersecurity Framework ("NIST CSF"). We do not represent that our practices conform to any specific technical standards or requirements; rather, we utilize the NIST CSF as a framework that informs how we design our approach to identify, evaluate, and address cybersecurity risks in our operations. In November 2025, we appointed a Vice President - Chief Information Officer ("CIO") to oversee our cybersecurity team, which actively works with third-party service providers 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.

Our third-party service providers provide extended coverage of our information technology and operational technology environments and conduct regular evaluations of our cybersecurity controls, including testing the design and operational effectiveness of our cybersecurity controls. We also share and receive threat intelligence with other 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 routinely conduct employee training, 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 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 oversees our cybersecurity policies, procedures, risk exposures and the steps taken by management to monitor and mitigate cybersecurity risks. Our cybersecurity team regularly updates and reports to the Audit Committee regarding cybersecurity risk exposure and our cybersecurity risk management strategy. 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 CIO is responsible for assessing, identifying and managing cybersecurity risks and is supported by the cybersecurity team. Top cybersecurity risks are also integrated into our overall ERM framework and overseen at the management level by the ERM Steering Committee. The CIO, who reports directly to the CFO 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 CIO in consultation with our CFO. In addition, our CIO has a direct line of communication with the Chief Executive Officer and General Counsel, as needed. Our CIO has over 30 years of experience in information technology and cybersecurity, holds a Bachelor of Science from Royal Holloway, University of London and has performed the role of CIO for over 7 years within a leading upstream E&P Company including the responsibility and accountability to the Audit Committee for cybersecurity.

***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. For example, a cyber-attack on a production control system could result in significant environmental and safety risks, such as a well incident, shut-in or spill that could cause business interruption, reputational damage, regulatory fines and penalties, costs of compliance and remediation or insurance limitations. Other 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. 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 any cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, although the Company periodically experiences cybersecurity incidents that are not deemed material to our business. A significant cybersecurity incident impacting us or third parties with whom we do business could materially and adversely disrupt our operations and affect our business strategy and performance, financial condition 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 — Technology and cybersecurity threats could disrupt our operations and cause reputational and financial harm to our business.

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 but may be continued until 2027.

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. Since the remands to state court, the three Jefferson Parish state court cases involving Stone have been relatively dormant. Only one of these cases has been set for trial, for the October-November 2027 docket.

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. The defendants that filed the removal have appealed the order of remand. Since the remand to state court, this case has been relatively dormant and has not been set for trial.

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 17, 2026, there were approximately 133 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 near-term. 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

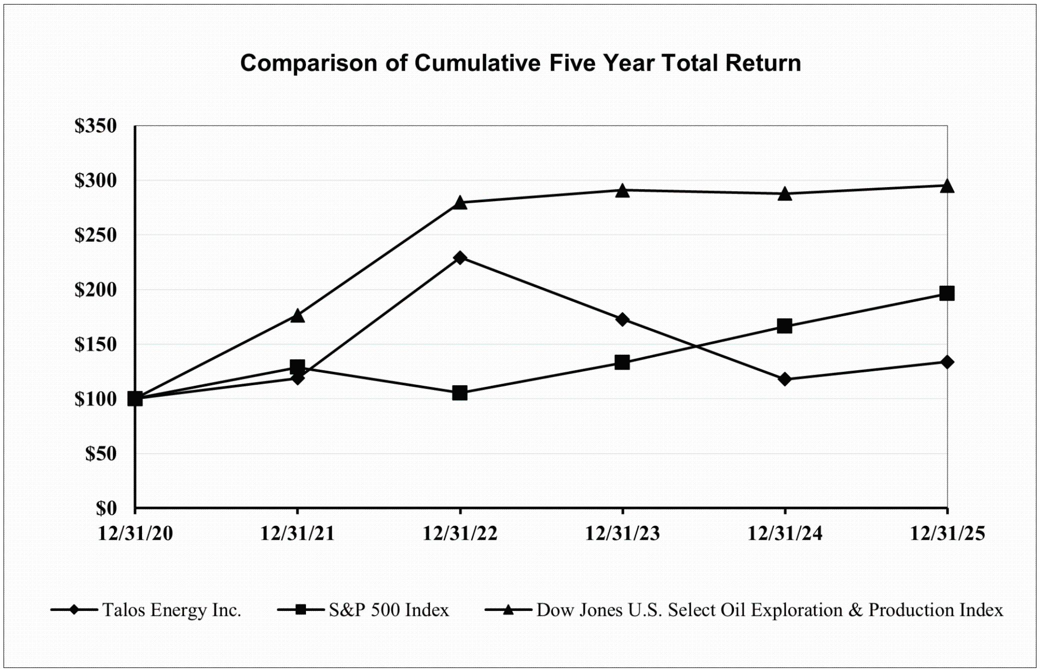
The following table sets forth information with respect to our repurchase of shares of common stock during the three months ended December 31, 2025 (in thousands, except for the share and per share amounts):

Period	Total Number of Shares Purchased	Average Price Paid	Total Number of Shares Purchased as Part of Publicly Announced Program(1)	Approximate Dollar Values of Shares that May Yet be Purchased Under the Program
October 1, 2025- October 31, 2025	—	$ —	—	$ 97,330
November 1, 2025- November 30, 2025	159,571	$ 10.97	159,571	$ 95,580
December 1, 2025- December 31, 2025	1,330,000	$ 11.05	1,330,000	$ 80,889
Total	1,489,571	$ 11.04	1,489,571	

(1) Refer to Part I, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Common Stock Repurchase Program" for additional information regarding our authorized share repurchase program.

Stockholder Return Performance Presentation

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of our common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for December 31, 2020 through December 31, 2025. The graph assumes that $100 was invested in our common stock and each index on December 31, 2020 and that dividends were reinvested.



	2020	2021	2022	2023	2024	2025
Talos Energy Inc.	$ 100	$ 119	$ 229	$ 173	$ 118	$ 134
S&P 500 Index	$ 100	$ 129	$ 105	$ 133	$ 166	$ 196
Dow Jones U.S. Exploration & Production Index	$ 100	$ 176	$ 280	$ 291	$ 288	$ 295

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 2025 and 2024 items and year-to-year comparisons between 2025 and 2024. Discussions of 2023 items and year-to-year comparisons between 2024 and 2023 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, 2024 filed with the SEC on February 27, 2025.

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 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.

Outlook

In 2026, we anticipate continued commodity price uncertainty, evolving global macroeconomic conditions, regulatory pressures, and shifting external expectations. Outlooks for crude oil and natural gas prices remain mixed, with some industry sources and analysts expecting prices to soften in 2026 while others anticipate improvement over 2025 levels, reflecting the ongoing unpredictability of global energy markets that will continue to influence the importance of maintaining financial and operational flexibility. Fluctuating commodity prices will directly affect our revenues.

We intend to prioritize high-margin oil production in 2026 underpinned by balanced investment in infrastructure-led development, exploration and appraisal, and multi-well development as part of the Monument Project. Capital expenditures guidance for 2026 is expected to range from $500 to $550 million. Abandonment and decommissioning expenditures are expected to range from $100 to $130 million. Non-operated capital expenditures are expected to be 40% of capital expenditures, which is an increase year over year and largely driven by the Monument Project. Approximately 10% of capital expenditures will be allocated to exploration. Production for 2026 is expected to be in the range of 62 to 66 MBopd; 85 to 90 MBoepd.

Tropical Storm Risk's extended outlook for the 2026 Atlantic hurricane season indicates activity in line with long-term averages—14 named storms, 7 hurricanes, and 4 major hurricanes. We incorporate expected weather-related downtime into our operational and financial planning to maintain flexibility and support achievement of production objectives.

Operational Update

CPN — During the first quarter of 2026, we successfully drilled the CPN well with first production expected in the second half of 2026. The CPN well will tie back to our non-operated Na Kika facility. Talos is the operator of CPN and holds a 65% working interest.

Katmai — The Katmai #2 well came online in the second quarter of 2025. The Katmai Field ties back to our operated Tarantula facility. In connection with the Katmai #2 well coming online, the Tarantula gross processing capacity was expanded to 35 MBoepd to accommodate higher volumes. During the fourth quarter of 2025, gross processing capacity at the Tarantula facility was increased to approximately 38 MBoepd. Talos is the operator of the Katmai Field and holds a 50% working interest.

Genovesa — During the fourth quarter of 2025, we temporarily shut-in production from the Genovesa well, which ties back to the non-operated Na Kika facility, due to a failure of the surface-controlled subsurface safety valve resulting in deferred production of approximately 3 MBoepd. We expect the Genovesa well to return to production in the third quarter of 2026 following completion of a planned workover. Talos is the operator of Genovesa and holds a 65% working interest.

Cardona — We successfully drilled and completed the Cardona well in late 2025. Production from the Cardona well ties back to our Pompano facility. Talos is the operator and holds a 65% working interest.

Manta Ray — During the fourth quarter of 2025, we participated in the drilling of the non-operated Manta Ray well. While the well encountered hydrocarbons, it was deemed non-commercial. Talos held a 40% working interest.

Daenerys — In August 2025, we announced successful drilling results at the Daenerys exploration prospect located on Walker Ridge blocks 106, 107, 150 and 151. The discovery well has been temporarily suspended to preserve its future utility. We plan to spud an appraisal well during the second quarter of 2026 to further define the discovered resource. Talos is the operator of Daenerys and holds a 27% working interest.

Recent Developments

The following encompasses recent developments since the filing of our Annual Report on Form 10-K for year ended December 31, 2024:

Amended and Restated Credit Agreement — On January 20, 2026, we entered into the Amended and Restated Credit Agreement (the "A&R Credit Agreement") with a syndicate of financial institutions as lenders and JPMorgan Chase Bank, N.A. as administrative agent. The initial borrowing base and the total commitments are each $700 million. The A&R Credit Agreement replaces the Company's amended credit agreement dated May 10, 2018. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information.

Lease Sale — The Big Beautiful Gulf 1 lease sale was held by BOEM on December 10, 2025. It was the first offshore oil and gas lease sale conducted under the new OBBBA. We emerged as the apparent high bidder on eleven of the twelve lease blocks on which we bid. As of February 17, 2026, we have been awarded eight of the lease blocks for which we were the high bidder and are awaiting BOEM's award decisions on our remaining high bids.

Surety Arrangements and Collateral Requirements — In early November 2025, we entered into various collateral funding and security arrangements ("CFSAs") to establish limits on the amount of aggregate collateral that our surety providers can require us to post. In exchange for our agreement to post the required amounts of collateral through July 1, 2031 and spend at least a specified amount on annual plugging and abandonment activities each year through 2030, the surety providers agreed not to (1) require additional collateral in excess of the agreed and scheduled amounts on existing surety bonds; (2) draw on collateral posted for the benefit of the sureties except under limited circumstances; (3) seek remedies for breaches of any surety agreement that are not an "Event of Default" as defined in the primary CFSA; or (4) cancel, or attempt to cancel, existing bonds unless requested by us.

For the three years commencing January 1, 2026 and for the subsequent two years commencing January 1, 2029, we are required to spend $90.0 million and $45.0 million on plugging and abandonment activities on an annual basis, respectively. As of December 31, 2025, our aggregate estimated collateral funding commitments under the CFSAs were $251.7 million through 2031. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies— Performance Obligations*" for the estimated collateral funding commitments by year under the CFSAs. Also, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Known Trends and Uncertainties — Financial Assurance Market Outlook."

The CFSAs generally contain certain events of default which, if triggered and not cured by us within the cure period, would terminate the standstill period and provide the sureties their full rights under their respective surety and indemnity agreements, including the right to call collateral. Events of default include, but are not limited to, the failure to maintain liquidity of $200.0 million or above a specified credit rating. However, if an event of default were to occur, it is anticipated we would be in a similar position than if we had not entered into the CFSAs given that the surety providers already have the right to demand collateral under existing surety bonds.

The CFSAs provide a multi-year framework to efficiently address the Company's collateral commitments and abandonment activities, while strengthening the relationship with our surety providers and supporting our long-term operational strategy.

Acquisition of Incremental Working Interest in Mississippi Canyon Blocks — On July 22, 2025, the Company completed the acquisition of an additional 75.2% and 50% working interest in U.S. Gulf of America Mississippi Canyon blocks 108 and 110, respectively, for $33.7 million of cash paid at closing. Prior to this acquisition, we owned an interest in and operated these developed and producing blocks. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

Enhanced Corporate Strategy — On June 17, 2025, we announced an enhanced corporate strategy designed to position the Company as a leading pure-play offshore exploration and production company. The strategy is built on three key pillars. The first pillar targets increased annualized free cash flow by improving our existing operations through capital efficiency, margin enhancement, commercial opportunities and general organizational improvements. The second pillar focuses on growth through high-margin organic projects and selective Deepwater acquisitions. The third pillar aims to build a long-lived and scaled portfolio in the U.S. Gulf of America and potentially other conventional basins. This strategy is underpinned by a disciplined capital allocation framework which prioritizes investing in projects expected to generate robust returns through commodity cycles, returning cash to shareholders, maintaining a strong balance sheet, and growing through selective opportunities.

Chief Financial Officer Transition — On May 16, 2025, Sergio L. Maiworm, Jr. informed the Board of Directors (the "Board") that he was resigning from his position as Executive Vice President and Chief Financial Officer of the Company, effective as of June 27, 2025. In connection with and following Mr. Maiworm's resignation, effective as of June 28, 2025, Gregory Babcock was appointed as Interim Chief Financial Officer to serve until a permanent Chief Financial Officer was appointed by the Board. On August 12, 2025, the Board appointed Mr. Zachary B. Dailey to serve as the Company's Executive Vice President and Chief Financial Officer and principal financial officer, effective August 18, 2025.

Acquisition of Incremental Working Interest in Monument Oil Discovery — On March 7, 2025, the Company completed the acquisition of an incremental 8.3% working interest in the Monument oil discovery in the U.S. Gulf of America located on certain Walker Ridge lease blocks. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

Appointment of President and Chief Executive Officer — Effective March 1, 2025, Mr. Paul Goodfellow was appointed President and Chief Executive Officer, principal executive officer and as an executive member of the Board.

Share Repurchase Program — During the twelve months ended December 31, 2025, we repurchased 12.6 million shares for $119.1 million exclusive of broker commissions under our share repurchase program, which was previously authorized by our Board, resulting in $80.9 million available under the share repurchase program. See "Liquidity and Capital Resources — Common Stock Repurchase Program" for additional information.

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 Energy Inc. ("QuarterNorth"), a privately held U.S. Gulf of America exploration and production company (the "QuarterNorth Acquisition"). 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 and have remained so during 2025 due in part to geopolitical tensions, the global economy, demand fluctuations, oversupply and macroeconomic uncertainty. As such, oil, natural gas and NGL prices have been, and may continue to be, subject to wide fluctuations. Outlooks for crude oil and natural gas prices remain mixed, with some industry sources and analysts expecting prices to soften in 2026 while others anticipate improvement over 2025 levels, reflecting the ongoing unpredictability of global energy markets that will continue to influence the importance of maintaining financial and operational flexibility. Our revenues, cash flow, profitability, access to capital, capital expenditures, and liquidity are directly influenced by commodity prices, and sustained lower prices could adversely affect our financial results. We use hedging instruments to reduce the impact of near-term price volatility. We also anticipate continuing to operate our business in a volatile market by prioritizing high-return development projects, focusing on cost control measures, and maintaining a strong balance sheet to provide financial, operational and capital spending flexibility under a range of price scenarios. We continue to monitor commodity price trends closely and will modify our plans within our strategy as appropriate. 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, 2025.

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.

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 may not adjust downward as fast as oil prices do. Inflation may also result in increases in the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise.

In 2025, the Federal Reserve cut interest rates three times, most recently in December, bringing the federal funds rate down to a target range of 3.50%–3.75%. These cuts mark the lowest rates since 2022. 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 2025, our ceiling test calculations resulted in an impairment of our oil and natural gas properties of $454.5 million. During 2024 and 2023 our ceiling test computations for our U.S. oil and gas properties did not result in an impairment. At December 31, 2025, the Company's ceiling test computation was based on SEC pricing of $65.37 per Bbl of oil, $3.61 per Mcf of natural gas and $19.22 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, 2025 and ending December 1, 2025 used in the determination of the SEC pricing was 10% lower, resulting in $58.76 per Bbl of oil, $3.26 per Mcf of natural gas and $17.35 per Bbl of NGLs, while all other factors remained constant, our oil and natural gas properties would have been impaired by approximately $807 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. The final rule was challenged in the U.S. District Court for the Western District of Louisiana (the "Western Louisiana District Court") by multiple oil and gas industry groups and the States of Mississippi, Louisiana, and Texas on June 17, 2024. The Western Louisiana District Court granted a stay of the litigation while BOEM pursues efforts to suspend, revise, or rescind the final rule. The Western Louisiana District Court's order temporarily limits full implementation of the final rule by limiting BOEM's ability to seek supplemental financial assurance to cases of sole liability properties and certain non-sole liability properties that are held by owners who are not financially strong, as described in the final rule, and that have no co-owners or predecessors who are financially strong.

On May 2, 2025, the DOI announced its intent to revise and develop a new rule that is consistent with the Trump Administration's 2020 proposed rule on financial assurance. The specific substance and timing of a revised rule cannot be predicted at this time. However, we anticipate that the new revised rule will revert to BOEM's former policy of considering the financial strength of both co-owners and predecessors in title when determining whether supplemental financial assurance is required, and if so, we anticipate the amount we would be required to bond under the revised rule would be significantly less than under the final rule.

Notwithstanding the status of the final rule or a new revised rule, BOEM stated it will continue to require lessees on the OCS to provide financial assurance in instances where BOEM determines there is a substantial risk of nonperformance of their 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.

In early November 2025, we entered into CFSAs to establish limits on the amount of aggregate collateral that our surety providers can require us to post through 2031. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies* and Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Recent Developments” for additional information.

***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.

***Future Offshore Leasing* —** Pursuant to OCSLA, the President may withdraw from disposition any of the unleased lands of the OCS. On January 6, 2025, former President Biden issued two memoranda (“Withdrawal Memoranda”) under OCSLA that withdrew approximately 625 million acres of the U.S. OCS, including the Eastern Planning Area of the Gulf of America from being considered for new oil or natural gas leases, including for exploration, development and production. However, the Western and Central Planning Areas in the Gulf of America were not included in President Biden’s withdrawal.

On January 20, 2025, President Trump issued an Executive Order revoking President Biden’s Withdrawal Memoranda and the U.S. Secretary of the Interior subsequently issued an order directing the DOI to “take all actions available to expedite the leasing of the OCS for oil and gas exploration and production.” Both President Biden’s and President Trump’s actions described above with respect to OCSLA have been challenged in federal district courts. On October 2, 2025, the Western District Court of Louisiana found in part for the plaintiffs challenging the Withdrawal Memoranda, which included the States of Louisiana, Alaska, Georgia and Mississippi, the Gulf Energy Alliance and the American Petroleum Institute, and ruled that the Withdrawal Memoranda are unlawful because they exceed the authority granted to the President under OCSLA. The challenge to President Trump’s revocation of the Withdrawal Memoranda remains ongoing.

Earlier in 2025, the Secretary of the Interior directed BOEM to initiate steps to develop a new schedule for offshore oil and gas lease sales in the OCS, which, once finalized, will be the 11th National OCS Program replacing the current 2024-2029 National OCS Program that includes just three lease sales in the Gulf of America. In June 2025, the comment period closed regarding BOEM’s notice requesting information and comments on the preparation of the 11th National OCS Program. On November 24, 2025, BOEM announced the availability of a draft proposed program (“DPP”) for OCS oil and gas leasing for the 2026-2031 period. The 2026-2031 DPP proposes a schedule of 34 OCS oil and gas lease sales during this five-year period, which includes 7 lease sales in the Gulf of America. These would be in addition to offshore oil and gas lease sales mandated by law outside the five-year program. We cannot determine when the 11th National OCS Program will be finalized, or how many lease sales will be scheduled.

The OBBBA, signed into law by President Trump on July 4, 2025, mandates that the BOEM conduct at least two offshore lease sales annually, of a minimum of 80 million acres (if available) in the Central and Western Gulf of America Planning Areas for the next 15 years, with at least one of these lease sales to be held by December 15, 2025. The OBBBA reduces the royalty rate for Gulf of America leases acquired at these sales to a minimum of 12.5% (pre-Inflation Reduction Act rates) but not greater than 16.67%. On August 19, 2025, the DOI announced the schedule for the 30 OBBBA-mandated Gulf of America lease sales, the first of which, named the Big Beautiful Gulf 1 Lease Sale was held on December 10, 2025. This lease sale took the place of the previously announced Lease Sale 262, which had been deferred by BOEM. The remaining lease sales are expected to be held each March and August for the years 2026 through 2039, with the last of these mandated Gulf of America lease sales expected in March 2040. On February 4, 2026, BOEM announced its Final Notice of Sale for the Big Beautiful Gulf 2 Lease Sale, which is scheduled to be held on March 11, 2026.

Executive, judicial and/or administrative action resulting in the withdrawal of OCS areas from consideration for new leasing activities or delays in scheduling OCS lease sales, particularly if such actions affect the Western and Central Planning Areas of the Gulf of America in which we currently or seek to operate, could have a material adverse effect on our ability to obtain new OCS leases and develop new assets, as well as negatively impact our financial condition and results of operations.

Update on National Marine Fisheries Service's Gulf of America Revised Biological Opinion — In August 2024, the federal district court for the District of Maryland vacated the 2020 Biological Opinion issued by the NMFS, related to oil and gas activities in the Gulf of America. The vacatur was initially effective December 20, 2024, but was later extended to May 21, 2025. On May 20, 2025, NMFS published its new Biological Opinion for the Gulf of America oil and gas program, superseding and replacing all prior biological opinions relating to the program. On the same day, two lawsuits were filed opposing the new Biological Opinion, one by several environmental groups (Sierra Club, the Center for Biological Diversity, Friends of the Earth and Turtle Island Restoration Network) who filed in the federal district court for the District of Maryland, and the other by the State of Louisiana, the API and Chevron U.S.A. Inc. who filed in the Western Louisiana District Court. Both lawsuits seek declaratory and injunctive relief. On January 23, 2026, the Western Louisiana District Court judge issued a summary judgment in favor of the State of Louisiana, API and Chevron U.S.A. Inc., and found the 2025 Biological Opinion unlawful. The 2025 Biological Opinion was remanded, without vacatur, to NMFS to correct the Biological Opinion's deficiencies. The 2025 Biological Opinion will remain active to avoid disruptive consequences to regulated parties. The outcome of the environmental groups' challenge in the Maryland District Court remains uncertain at this time.

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,		
	2025	2024	2023
Oil	88 %	92 %	93 %
Natural gas	10 %	5 %	5 %
NGL	2 %	3 %	2 %

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,		
	2025	2024	2023
Oil:			
NYMEX WTI high per Bbl	$ 75.74	$ 85.35	$ 89.43
NYMEX WTI low per Bbl	$ 57.97	$ 69.95	$ 70.25
Average NYMEX WTI per Bbl	$ 65.45	$ 76.54	$ 77.63
Average oil sales price per Bbl (including commodity derivatives)	$ 68.18	$ 75.07	$ 73.59
Average oil sales price per Bbl (excluding commodity derivatives)	$ 64.84	$ 75.01	$ 75.17
Natural Gas:			
NYMEX Henry Hub high per MMBtu	$ 4.26	$ 3.18	$ 3.27
NYMEX Henry Hub low per MMBtu	$ 2.91	$ 1.49	$ 2.14
Average NYMEX Henry Hub per MMBtu	$ 3.53	$ 2.19	$ 2.54
Average natural gas sales price per Mcf (including commodity derivatives)	$ 3.70	$ 2.65	$ 3.32
Average natural gas sales price per Mcf (excluding commodity derivatives)	$ 3.67	$ 2.57	$ 2.60
NGLs:			
NGL realized price as a % of average NYMEX WTI	28 %	27 %	23 %

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 A&R Credit Agreement 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 may 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 may 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,		
	2025	**2024**	**Change**
Revenues:			
Oil	$ 1,560,401	$ 1,806,148	$ (245,747)
Natural gas	169,445	105,528	63,917
NGL	50,224	61,892	(11,668)
Total revenues	$ 1,780,070	$ 1,973,568	$ (193,498)
Production Volumes:			
Oil (MBbls)	24,065	24,078	(13)
Natural gas (MMcf)	46,122	41,078	5,044
NGL (MBbls)	2,782	2,969	(187)
Total production volume (MBoe)	34,534	33,893	641
Daily Production Volumes by Product:			
Oil (MBblpd)	65.9	65.8	0.1
Natural gas (MMcfpd)	126.4	112.2	14.2
NGL (MBblpd)	7.6	8.1	(0.5)
Total production volume (MBoepd)	94.6	92.6	2.0
Average Sale Price per Unit:			
Oil (per Bbl)	$ 64.84	$ 75.01	$ (10.17)
Natural gas (per Mcf)	$ 3.67	$ 2.57	$ 1.10
NGL (per Bbl)	$ 18.05	$ 20.85	$ (2.80)
Price per Boe	$ 51.55	$ 58.23	$ (6.68)
Price per Boe (including realized commodity derivatives)	$ 53.90	$ 58.37	$ (4.47)

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	$ (244,772)	$ (975)	$ (245,747)
Natural gas	50,954	12,963	63,917
NGL	(7,769)	(3,899)	(11,668)
Total revenues	$ (201,587)	$ 8,089	$ (193,498)

Volumetric Analysis — Production volumes increased by 2.0 MBoepd to 94.6 MBoepd for the year ended December 31, 2025. The increase was primarily due to 6.4 MBoepd in production from the oil and natural gas assets acquired in the QuarterNorth Acquisition that closed in early March 2024. Additionally, there were increases of 2.3 MBoepd and 1.2 MBoepd of production from our Katmai West #2 and Sunspear wells, respectively, both of which commenced initial production in June 2025. Production volumes also increased 2.0 MBoepd due to the recompletion of one of our operated Brutus wells, which commenced initial production in July 2024. These increases were partially offset by 10.6 MBoepd related to natural decline of the production rate of existing oil and natural gas wells. The absence of weather-related downtime during the 2025 hurricane season compared to the same period in 2024 was favorable to our production volumes.

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,	
	2025	2024
Lease operating expenses	$ 546,716	$ 566,041
Lease operating expenses per Boe	$ 15.83	$ 16.70

Total lease operating expenses for the year ended December 31, 2025 decreased by approximately $19.3 million, or 3%. The decrease is primarily related to a $40.2 million decrease in facility and workover expenses primarily related to the HP-1 dry dock and major well workover expenses at the Phoenix Field and the Garden Banks 506 Field compared to the same period in 2024. This was partially offset by a $16.9 million increase in direct lease operating expenses due to the QuarterNorth Acquisition that closed in late first quarter 2024.

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,	
	2025	2024
Depreciation, depletion and amortization	$ 1,056,281	$ 1,023,558

Depreciation, depletion and amortization expense for the year ended December 31, 2025 increased by approximately $32.7 million, or 3%. This increase was primarily driven by increased production volumes of 2.0 MBoepd discussed above.

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,	
	2025	2024
Upstream Segment	$ 155,368	$ 191,063
CCS Segment	—	10,454
Total general and administrative expense	$ 155,368	$ 201,517
Upstream general and administrative expense per Boe	$ 4.50	$ 5.64

General and administrative expense for the year ended December 31, 2025, decreased by approximately $46.1 million, or 23%. This decrease was primarily driven by Upstream Segment transactions costs, severance costs and additional general and administrative expenses incurred in 2024 relating to the QuarterNorth Acquisition of $46.6 million or $2.65 per Boe. Additionally, there was a decrease in the CCS Segment transaction costs, severance costs and expenses of $11.0 million due to the divestiture of our CCS business. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information. This decrease was partially offset by an increase in non-cash equity-based compensation of $4.0 million compared to the same period in 2024. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Share Based Compensation* for additional information.

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,	
	2025	2024
Accretion expense	$ 125,296	$ 117,604
Impairment of oil and natural gas properties	$ 454,482	$ —
Other operating (income) expense	$ 1,789	$ (109,454)
Interest expense	$ 163,381	$ 187,638
Price risk management activities (income) expense	$ (105,455)	$ 1,458
Equity method investment (income) expense	$ 1,807	$ 10,289
Other (income) expense	$ (15,520)	$ 44,930
Income tax (benefit) expense	$ (109,169)	$ 5,003

Accretion Expense — During the year ended December 31, 2025, we recorded $125.3 million of accretion expense compared to $117.6 million during the year ended December 31, 2024. The change is primarily the result of a $4.4 million increase in accretion associated with the asset retirement obligations assumed as part of the QuarterNorth Acquisition combined with a higher asset retirement obligation subject to accretion expense. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

Impairment of oil and natural gas properties — During the year ended December 31, 2025, we recorded a $454.5 million impairment of our oil and natural gas properties. The impairment is a result of our ceiling test evaluation as described in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 4 — *Property, Plant and Equipment*.

Other Operating (Income) Expense — During the year ended December 31, 2024, we recognized a gain of $100.4 million from the sale of our wholly owned subsidiary, Talos Low Carbon Solutions LLC to TotalEnergies E&P USA, Inc. (the "TLCS Divestiture"). See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for further discussion.

Interest Expense — During the year ended December 31, 2025, we recorded $163.4 million of interest expense compared to $187.6 million during the year ended December 31, 2024. The change is primarily due to a $19.2 million decrease in interest expense related to the Bank Credit Facility as a result of paying off all borrowings under our Bank Credit Facility balance prior to December 31, 2024. Additionally, there was a decrease of $4.9 million of fees associated with an unutilized bridge loan during the corresponding period in 2024. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information.

Price Risk Management Activities — The income of $105.5 million for the year ended December 31, 2025 consisted of $81.5 million in cash settlement gains and $24.0 million in non-cash gains from the increase in the fair value of our open derivative contracts. 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.

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, of which $8.0 million related to our CCS Segment that was divested in March 2024.

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, 2025, we recorded $109.2 million of income tax benefit compared to $5.0 million of income tax expense during the year ended December 31, 2024. The benefit of $109.2 million for the year ended December 31, 2025 is primarily due to current year activity offset with income tax expense of $28.8 million related to recording a valuation allowance on its U.S. federal deferred tax assets. For the year ended December 31, 2024, we recorded $5.0 million of income tax expense primarily related to state income tax expense of $17.7 million and an income tax benefit of $10.1 million related to current year activity inclusive of nontaxable or nondeductible items. 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, Adjusted EBITDA and Adjusted EBITDA attributable to Talos Energy Inc.

"EBITDA," "Adjusted EBITDA," and "Adjusted EBITDA attributable to Talos Energy Inc." 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, Adjusted EBITDA and Adjusted EBITDA attributable to Talos Energy Inc. 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) attributable to Talos Energy Inc. plus net income (loss) attributable to noncontrolling interest, plus interest expense, income tax benefit (expense), depreciation, depletion and amortization, and accretion expense.
- ***Adjusted EBITDA —*** EBITDA plus non-cash impairment 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 impairment of other well equipment and non-cash equity-based compensation expense.
- ***Adjusted EBITDA attributable to Talos Energy Inc. —*** Adjusted EBITDA, less adjustments for noncontrolling interest.

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,		
	2025	2024	2023
Net income (loss) attributable to Talos Energy Inc.	$ (494,290)	$ (76,393)	$ 187,332
Net income (loss) attributable to noncontrolling interest	(1,034)	—	—
Net income (loss)	(495,324)	(76,393)	187,332
Interest expense	163,381	187,638	173,145
Income tax (benefit) expense	(109,169)	5,003	(60,597)
Depreciation, depletion and amortization	1,056,281	1,023,558	663,534
Accretion expense	125,296	117,604	86,152
EBITDA	740,465	1,257,410	1,049,566
Impairment of oil and natural gas properties	454,482	—	—
Transaction and other (income) expense[(1)]	5,001	(59,022)	(33,295)
Decommissioning obligations[(2)]	3,245	8,559	11,879
Derivative fair value (gain) loss[(3)]	(105,455)	1,458	(80,928)
Net cash received (paid) on settled derivative instruments[(3)]	81,471	4,710	(9,457)
(Gain) loss on debt extinguishment	—	60,256	—
Non-cash equity-based compensation expense	18,418	14,462	12,953
Adjusted EBITDA	$ 1,197,627	$ 1,287,833	$ 950,718

(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 in costs related to the EnVen Acquisition, inclusive of $25.3 million for the year ended December 31, 2023. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions 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 related to a 49.9% equity interest in Talos Mexico sold to Zamajal. 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 for the year ended December 31, 2023. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Equity Method Investments*.

(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, operating costs, working capital, debt service, share repurchases, future collateral payments 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 new bank credit facility currently has a borrowing base of $700.0 million. As of December 31, 2025, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $965.4 million. Letters of credit that are outstanding reduce the available revolving credit commitments. The next redetermination of our borrowing base is expected in the second quarter of 2026. The borrowing base in reserve-based lending, which is influenced by banking regulations and guidelines, is a dynamic figure subject to regular redeterminations. Changes in reserve estimations (e.g., lower production forecasts or reduced proved reserves), downward adjustments to the lender's internal price deck (i.e., commodity price expectations) and ongoing production can lead to a reduction in the borrowing base, impacting available liquidity under our bank credit facility. 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 and Other Expenditures **—** The following is a table of our capital and other expenditures, excluding acquisitions, for the year ended December 31, 2025 (in thousands):

U.S. drilling & completions	$	394,264
Asset management[(1)]		31,991
Seismic and G&G, land, capitalized G&A and other		67,812
Total capital expenditures		494,067
Plugging & abandonment		117,847
Decommissioning obligations settled[(2)]		1,102
Investment in Mexico		4,559
Total capital and other expenditures	$	617,575

(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 our bank credit facility, provide sufficient liquidity to fund our 2026 capital spending program of $500.0 million to $550.0 million and plugging & abandonment and decommissioning obligations of $100.0 million to $130.0 million. However, our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under our 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.

Surety Agreements and Collateral Requirements **—** The CFSAs require us to post agreed upon amounts of collateral through July 1, 2031. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Recent Developments" for additional information on estimated collateral funding commitments under the CFSAs. The collateral requirements may be secured by cash or letters of credit which will reduce our liquidity.

Common Stock Repurchase Program **—** Since the Board initially approved a share repurchase program of $100.0 million on March 20, 2023, the Board has approved increases in share repurchase capacity of $150.0 million on July 22, 2024 and approximately $42.5 million on March 25, 2025, for a total aggregate repurchase capacity of approximately $292.5 million, with approximately $80.9 million remaining under the authorized program as of December 31, 2025. During the twelve months ended December 31, 2025, we repurchased 12.6 million shares for $119.1 million exclusive of broker commissions. Since the inception of our share repurchase program in March 2023, we have repurchased an aggregate of 20.0 million shares under our authorized program for a total amount of $211.6 million, exclusive of broker commissions. The share repurchase program has no set term limits. 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. Our share repurchase program is subject to the 1% U.S. federal excise tax on certain repurchases of stock by publicly traded U.S. corporations.

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,			
	2025		2024	
Operating activities	$	935,826	$	962,593
Investing activities	$	(546,746)	$	(1,320,279)
Financing activities	$	(164,522)	$	436,119

Operating Activities — Net cash provided by operating activities decreased $26.8 million in 2025 compared to 2024. The change between periods is primarily attributable to an $80.9 million increase in cash from earnings after non-cash items, as presented in the Consolidated Statements of Cash Flows under Part IV, Item 15. Exhibits and Financial Statement Schedules, offset by a $9.1 million increase in settlement of asset retirement obligations. There was a $98.6 million decrease in cash due to changes in working capital accounts across all categories of operating assets and liabilities. Working capital at any specific point in time is subject to many variables, including commodity prices, production volumes, and the timing of cash receipts and payments.

Investing Activities — Net cash used in investing activities decreased $773.5 million in 2025 compared to 2024. Payments for acquisitions (net of cash acquired) decreased by $886.2 million. During the year ended December 31, 2024, payment for acquisitions was $936.2 million, of which $916.0 million related to the QuarterNorth Acquisition. During the year ended December 31, 2025, payment for acquisitions was $50.0 million. Proceeds from the sale of businesses decreased by $146.7 million, all of which is attributable to the TLCS Divestiture. Additionally, contributions to equity method investees decreased by $18.4 million primarily attributable to the TLCS Divestiture. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 3 — *Acquisitions and Divestitures* for additional information on the QuarterNorth Acquisition and the TLCS Divestiture.

Financing Activities — Net cash provided by financing activities increased $600.6 million in 2025 compared to 2024. 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. During the year ended December 31, 2025, we repurchased $119.5 million of our common stock through our common stock repurchase program compared to $45.2 million in the corresponding period in 2024 both amounts inclusive of broker commissions. See subsection above entitled "— Liquidity and Capital Resources — Common Stock Repurchase Program" for additional information. Furthermore, the Bank Credit Facility had no activity during the year ended December 31, 2025 compared to net repayments of $200.0 million during the corresponding period in 2024.

Overview of Debt Instruments

Financing Arrangements — As of December 31, 2025, total debt, net of discount and deferred financing costs, was approximately $1,226.2 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, 2025. For additional details on our debt, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt*.

Bank Credit Facility — We maintained a Bank Credit Facility with a syndicate of financial institutions. The borrowing base was 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 delivered to the administrative agent of our Bank Credit Facility. As discussed above under "— Recent Developments," the A&R Credit Agreement replaced the Bank Credit Facility in January 2026. For additional details on our Bank Credit Facility and the A&R Credit Agreement, 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. The following discussion summarizes our material cash requirements from known contractual obligations as of December 31, 2025:

Debt — We have two separate principal payments of $625.0 million each, corresponding to two different series of notes maturing in February 2029 and February 2031 with fixed interest rates of 9.000% and 9.375%, respectively. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 8 — *Debt* for additional information. Our estimated interest payments associated with our debt is $525.5 million, of which $119.9 million is due within the next twelve months.

Vessel commitments — We have $42.9 million in 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. These vessel commitments do not extend beyond a one-year period.

Operating lease obligations — See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 5 — *Leases* for additional information.

Finance lease — We have $67.6 million in commitments related to our lease agreement for the HP-1 floating production facility in the Phoenix Field, which is utilized in our oil and natural gas development activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 5 — *Leases* for additional information, which contemplates renewal period that we are reasonably certain to exercise.

Firm transportation commitments — We have agreements in place with pipeline carriers for future transportation of oil and gas production. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies* for additional information.

Plugging and Abandonment — We have arrangements with our surety providers which require us to spend at least a specified amount on plugging and abandonment activities each year. For the three years commencing January 1, 2026 and for the subsequent two years commencing January 1, 2029,we are required to spend $90.0 million and $45.0 million on these activities on an annual basis, respectively. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Commitments and Contingencies* for additional information.

Performance Obligations — As of December 31, 2025, 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 $97.4 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.

Our proved oil, natural gas and NGL reserves are estimated 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.

Estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. Our reserves at December 31, 2025 and 2024 were fully engineered by NSAI and audited by them at December 31, 2023. 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 10 percent lower, depreciation, depletion and amortization in the year ended December 31, 2025 would have increased by an estimated $110.8 million.

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. As a result of the Company's ceiling test computations, an impairment of its U.S. oil and natural gas properties was recorded during the year ended December 31, 2025 of $454.5 million. If the unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the period beginning January 1, 2025 and ending December 1, 2025 used in the determination of the SEC pricing was 10% lower, while all other factors remained constant, our oil and natural gas properties would have been impaired by approximately $807 million.

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 decommissioning costs in 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. federal and state and non-U.S. 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 primarily 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 A&R Credit Agreement 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 A&R Credit Agreement, 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 A&R Credit Agreement) 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, 2025, our average oil price realizations after the effect of derivatives decreased 9% to $68.18 per Bbl from $75.07 per Bbl in the comparable 2024 period. Our average natural gas price realizations after the effect of derivatives increased 40% during the year ended December 31, 2025 to $3.70 per Mcf from $2.65 per Mcf in the comparable 2024 period.

Price Risk Management Activities

Historically, we have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production primarily through the use of oil and natural gas swaps and costless collars. 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 7,371 MBbls of crude oil and 10,465 MMBtu of natural gas at December 31, 2025, with a net derivative asset position of $47.7 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, 2025 (in thousands):

		Oil and Natural Gas Derivatives			
		Ten Percent Increase		Ten Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
Price impact[(1)]	$ 47,712	$ 9,629	$ (38,083)	$ 88,273	$ 40,561

(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, 2025, 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 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, 2025, 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.

We are subject to the risk of changes in interest rates under our bank credit facility. In addition, the terms of our A&R Credit Agreement require us to pay higher interest rates as we utilize a larger percentage of our available borrowing base.

Item 8. Financial Statements and Supplementary Data

See the Consolidated Financial Statements and Report of Independent Registered Public Accounting Firm as of December 31, 2025 and 2024 and for the years ended December 31, 2025, 2024 and 2023, included in Part IV, Item 15. Exhibits and Financial Statements Schedules.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a- 15(e) and 15d- 15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Based on such evaluation, our chief executive officer and chief financial officer have concluded that as of December 31, 2025, 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, 2025 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. Our independent registered public accounting firm, Ernst & Young LLP, has issued an audit report with respect to our internal control over financial reporting, which is included in this Annual Report.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the fourth quarter of 2025 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, 2025, 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 2026 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2025.

Our Board of Directors has adopted a Code of Conduct 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 Conduct 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 included 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 2026 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2025.

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 2026 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2025.

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 2026 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2025.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2026 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2025.

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	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).
4.2	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	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).
4.4	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).

4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	Amended and Restated Credit Agreement, dated as of January 20, 2026, 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 10.1 to Talos Energy Inc.'s Form 8-K12 (File No. 001-38497) filed with the SEC on January 22, 2026).
10.1	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).
10.2†	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).
10.3†	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).
10.4†	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).
10.5†	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).
10.6†	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).
10.7	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).
10.8†	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).
10.9†	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).
10.10†	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).
10.11†	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).

10.12†	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).
10.13†	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).
10.14†	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).
10.15†	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).
10.16†	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).
10.17†	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).
10.18†	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).
10.19†	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).
10.20	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).
10.21	Amendment to Cooperation Agreement effective as of December 8, 2025, 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 11, 2025).
10.22†	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).
10.23†	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).
10.24†	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).
10.25†	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).
10.26†	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).
10.27†	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).
10.28†	Form of Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Stock Price Hurdle) (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, 2025).

10.29*	First Amendment to the Equity Interest Purchase Agreement, dated June 24 2025, by and between Talos Energy LLC, Talos Production Inc., and Zamajal, S.A. de C.V.
10.30*	Second Amendment to the Equity Interest Purchase Agreement, dated December 11, 2025, by and between Talos Energy LLC, Talos Production Inc., and Zamajal, S.A. de C.V.
19.1	Talos Energy Inc. Insider Trading Policy (incorporated by reference to Exhibit 19.1 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 27, 2025).
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, 2025.
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 24, 2026	By:	/s/ Zachary B. Dailey
			Zachary B. Dailey
			Executive Vice President and Chief Financial Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints William S. Moss, III and Zachary B. Dailey, 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/ Paul Goodfellow Paul Goodfellow	Chief Executive Officer (Principal Executive Officer)	February 24, 2026
/s/ Zachary B. Dailey Zachary B. Dailey	Chief Financial Officer (Principal Financial Officer, Authorized Signatory)	February 24, 2026
/s/ Gregory Babcock Gregory Babcock	Chief Accounting Officer (Principal Accounting Officer, Authorized Signatory)	February 24, 2026
/s/ Paula R. Glover Paula R. Glover	Director	February 24, 2026
/s/ Neal P. Goldman Neal P. Goldman	Director	February 24, 2026
/s/ John “Brad” Juneau John “Brad” Juneau	Director	February 24, 2026
/s/ Richard Sherrill Richard Sherrill	Director	February 24, 2026
/s/ Charles M. Sledge Charles M. Sledge	Director	February 24, 2026
/s/ Shandell Szabo Shandell Szabo	Director	February 24, 2026

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, 2025 and 2024, 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, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 24, 2026 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 oil and natural gas properties and full cost ceiling impairment

Description of the Matter

At December 31, 2025, the net book value of the Company’s proved oil and natural gas properties was $3,949 million, and depreciation, depletion and amortization (DD&A) and the full cost ceiling impairment of oil and natural gas properties were $1,054 million and $454 million, respectively for the year then ended. 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 natural gas reserves, as estimated by independent petroleum engineers. The Company’s capitalized costs are limited to a ceiling based on the present value of future net revenues from proved oil and natural gas reserves, discounted at 10%.

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 and internal petroleum engineers (“engineers”) in estimating proved oil and natural gas reserves. Estimating reserves also requires the selection and evaluation of inputs, including historical production, oil and natural gas price assumptions, operating and capital costs assumptions, among others. Because of the complexity involved in estimating oil and natural gas reserves, management engaged independent petroleum engineers to prepare the proved oil and natural gas reserve estimates for all properties as of December 31, 2025.

Auditing the Company's DD&A expense and full cost ceiling impairment calculations is complex because of the use of the work of engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and natural gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls that address the risks of material misstatement relating to the DD&A expense and the full cost ceiling impairment calculations for oil and natural gas properties, including management's controls over the completeness and accuracy of the financial data and inputs used by the engineers for use in estimating proved oil and natural gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the engineers responsible for the preparation of the reserve estimates. We tested the completeness and accuracy of the financial data and inputs used by the engineers in the estimation of proved oil and natural 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 to the proved oil and natural gas reserve estimate. We also tested the DD&A expense and full cost ceiling impairment calculations for oil and natural gas properties to assess whether they are based on the appropriate proved oil and natural gas reserve volumes as estimated by the engineers.

Asset retirement obligations

Description of the Matter

At December 31, 2025, asset retirement obligations total $1,332 million. 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 decommissioning engineers to estimate the expected cash outflows for the Company's asset retirement obligation as of December 31, 2025.

Auditing management's accounting for retirement obligations was especially challenging as significant judgment is required by the Company in determining the obligations. 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 timing of asset retirement activities.

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 obligations, including the controls over management's review of the significant assumptions described above.

To test the asset retirement obligations, 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, analyzed consistency between the timing of asset retirement activities and projected productive life of the properties, compared 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 24, 2026

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, 2025, 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, 2025, 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, 2025 and 2024, 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, 2025, and the related notes and financial statement schedule listed in the Index at Item 15(a) and our report dated February 24, 2026 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 24, 2026

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

	Year Ended December 31, 2025	2024
ASSETS		
Current assets:		
Cash and cash equivalents	$ 362,809	$ 108,172
Accounts receivable, net	323,058	404,258
Assets from price risk management activities	54,420	33,486
Prepaid assets	83,080	77,487
Other current assets	17,939	35,980
Total current assets	841,306	659,383
Property and equipment:		
Proved properties	10,621,012	9,784,832
Unproved properties, not subject to amortization	480,555	587,238
Other property and equipment	22,643	35,069
Total property and equipment	11,124,210	10,407,139
Accumulated depreciation, depletion and amortization	(6,686,575)	(5,191,865)
Total property and equipment, net	4,437,635	5,215,274
Other long-term assets:		
Restricted cash	76,181	106,260
Assets from price risk management activities	—	253
Equity method investments	112,382	111,269
Other well equipment	49,307	58,306
Notes receivable, net	19,636	17,748
Operating lease assets	9,214	11,294
Other assets	6,396	12,008
Total assets	$ 5,552,057	$ 6,191,795
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 92,979	$ 117,055
Accrued liabilities	290,223	326,913
Accrued royalties	59,768	77,672
Current portion of asset retirement obligations	112,489	97,166
Liabilities from price risk management activities	6,708	6,474
Accrued interest payable	48,972	49,084
Current portion of operating lease liabilities	3,657	3,837
Other current liabilities	29,925	44,854
Total current liabilities	644,721	723,055
Long-term liabilities:		
Long-term debt	1,226,189	1,221,399
Asset retirement obligations	1,219,639	1,052,569
Liabilities from price risk management activities	—	3,537
Operating lease liabilities	11,956	15,489
Other long-term liabilities	281,429	416,041
Total liabilities	3,383,934	3,432,090
Commitments and contingencies (Note 15)		
Equity:		
Talos Energy Inc. stockholders’ equity:		
Preferred stock; $0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of December 31, 2025 and 2024, respectively	—	—
Common stock; $0.01 par value; 270,000,000 shares authorized; 188,530,052 and 187,434,908 shares issued as of December 31, 2025 and 2024, respectively	1,885	1,874
Additional paid-in capital	3,296,643	3,274,626
Accumulated deficit	(918,400)	(424,110)
Treasury stock, at cost; 20,015,369 and 7,417,385 shares as of December 31, 2025 and 2024, respectively	(212,144)	(92,685)
Total Talos Energy Inc. stockholders' equity	2,167,984	2,759,705
Noncontrolling interest	139	—
Total equity	2,168,123	2,759,705
Total liabilities and equity	$ 5,552,057	$ 6,191,795

See accompanying notes.

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

	Year Ended December 31, 2025	2024	2023
Revenues:			
Oil	1,560,401	$ 1,806,148	$ 1,357,732
Natural gas	169,445	105,528	68,034
NGL	50,224	61,892	32,120
Total revenues	1,780,070	1,973,568	1,457,886
Operating expenses:			
Lease operating expense	546,716	566,041	389,621
Production taxes	418	1,377	2,451
Depreciation, depletion and amortization	1,056,281	1,023,558	663,534
Impairment of oil and natural gas properties	454,482	—	—
Accretion expense	125,296	117,604	86,152
General and administrative expense	155,368	201,517	158,493
Other operating (income) expense	1,789	(109,454)	(52,155)
Total operating expenses	2,340,350	1,800,643	1,248,096
Operating income (expense)	(560,280)	172,925	209,790
Interest expense	(163,381)	(187,638)	(173,145)
Price risk management activities income (expense)	105,455	(1,458)	80,928
Equity method investment income (expense)	(1,807)	(10,289)	(3,209)
Other income (expense)	15,520	(44,930)	12,371
Net income (loss) before income taxes	(604,493)	(71,390)	126,735
Income tax benefit (expense)	109,169	(5,003)	60,597
Net income (loss)	$ (495,324)	$ (76,393)	$ 187,332
Net income (loss) attributable to noncontrolling interest	(1,034)	—	—
Net income (loss) attributable to Talos Energy Inc.	$ (494,290)	$ (76,393)	$ 187,332
Net income (loss) per share attributable to common stockholders:			
Basic	$ (2.82)	$ (0.44)	$ 1.56
Diluted	$ (2.82)	$ (0.44)	$ 1.55
Weighted average common shares outstanding:			
Basic	175,136	175,605	119,894
Diluted	175,136	175,605	120,752

See accompanying notes.

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

	Talos Energy Inc. Stockholders' Equity						
	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Common Stock Held in Treasury	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
Balance at December 31, 2022	$ 826	$ 1,699,799	$ (535,049)	$ —	$ 1,165,576	$ —	$ 1,165,576
Equity-based compensation	—	25,008	—	—	25,008	—	25,008
Equity-based compensation tax withholdings	—	(7,459)	—	—	(7,459)	—	(7,459)
Equity-based compensation stock issuances	11	(11)	—	—	—	—	—
Issuance of common stock for acquisition (Note 3)	438	831,760	—	—	832,198	—	832,198
Purchase of treasury stock	—	—	—	(47,504)	(47,504)	—	(47,504)
Net income (loss)	—	—	187,332	—	187,332	—	187,332
Balance at December 31, 2023	1,275	2,549,097	(347,717)	(47,504)	2,155,151	—	2,155,151
Equity-based compensation	—	21,987	—	—	21,987	—	21,987
Equity-based compensation tax withholdings	—	(6,206)	—	—	(6,206)	—	(6,206)
Equity-based compensation stock issuances	11	(11)	—	—	—	—	—
Issuance of common stock for acquisition (Note 3)	243	322,387	—	—	322,630	—	322,630
Issuance of common stock (Note 10)	345	387,372			387,717	—	387,717
Purchase of treasury stock	—	—	—	(45,181)	(45,181)	—	(45,181)
Net income (loss)	—	—	(76,393)	—	(76,393)	—	(76,393)
Balance at December 31, 2024	1,874	3,274,626	(424,110)	(92,685)	2,759,705	—	2,759,705
Equity-based compensation	—	25,616	—	—	25,616	—	25,616
Equity-based compensation tax withholdings	—	(3,588)	—	—	(3,588)	—	(3,588)
Equity-based compensation stock issuances	11	(11)	—	—	—	—	—
Issuance of common stock for acquisition (Note 3)	—	—	—	—	—	—	—
Issuance of common stock (Note 10)	—	—	—	—	—	—	—
Initial consolidation of subsidiary	—	—	—	—	—	1,173	1,173
Purchase of treasury stock	—	—	—	(119,459)	(119,459)	—	(119,459)
Net income (loss)	—	—	(494,290)	—	(494,290)	(1,034)	(495,324)
Balance at December 31, 2025	$ 1,885	$ 3,296,643	$ (918,400)	$ (212,144)	$ 2,167,984	$ 139	$ 2,168,123

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
Balance at December 31, 2022	82,570,328	—	82,570,328
Equity-based compensation stock issuances	1,110,143	—	1,110,143
Issuance of common stock for acquisitions	43,799,890	—	43,799,890
Purchase of treasury stock	—	(3,400,000)	(3,400,000)
Balance at December 31, 2023	127,480,361	(3,400,000)	124,080,361
Equity-based compensation stock issuances	1,105,095	—	1,105,095
Issuance of common stock for acquisitions	24,349,452	—	24,349,452
Issuance of common stock	34,500,000	—	34,500,000
Purchase of treasury stock	—	(4,017,385)	(4,017,385)
Balance at December 31, 2024	187,434,908	(7,417,385)	180,017,523
Equity-based compensation stock issuances	1,095,144	—	1,095,144
Purchase of treasury stock	—	(12,597,984)	(12,597,984)
Balance at December 31, 2025	188,530,052	(20,015,369)	168,514,683

See accompanying notes.

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

	Year Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income (loss)	$ (495,324)	$ (76,393)	$ 187,332
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion, amortization and accretion expense	1,181,577	1,141,162	749,686
Impairment of oil and natural gas properties	454,482	—	—
Amortization of deferred financing costs and original issue discount	8,359	9,303	15,039
Equity-based compensation expense	18,418	14,462	12,953
Price risk management activities (income) expense	(105,455)	1,458	(80,928)
Net cash received (paid) on settled derivative instruments	81,471	4,710	(9,457)
Equity method investment (income) expense	1,807	10,289	3,209
Loss (gain) on extinguishment of debt	—	60,256	—
Settlement of asset retirement obligations	(117,847)	(108,789)	(86,615)
Loss (gain) on sale of assets	381	38	(66,115)
Loss (gain) on sale of business	—	(100,482)	—
Changes in operating assets and liabilities:			
Accounts receivable	85,459	8,576	20,352
Other current assets	15,895	(6,964)	7,066
Accounts payable	(22,833)	(3,831)	(60,401)
Other current liabilities	(66,563)	1,290	(96,960)
Other non-current assets and liabilities, net	(104,001)	7,508	(76,092)
Net cash provided by (used in) operating activities	935,826	962,593	519,069
Cash flows from investing activities:			
Exploration, development and other capital expenditures	(481,905)	(508,914)	(561,434)
Cash acquired in excess of payments for acquisitions	1,690	—	17,617
Payments for acquisitions, net of cash acquired	(49,978)	(936,214)	—
Proceeds from (cash paid for) sale of property and equipment, net	1,716	1,161	73,004
Contributions to equity method investees	(4,559)	(22,988)	(29,447)
Investment in intangible assets	—	—	(12,366)
Proceeds from sales of business	—	146,676	—
Other	(13,710)	—	—
Net cash provided by (used in) investing activities	(546,746)	(1,320,279)	(512,626)
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)
Proceeds from Bank Credit Facility	—	880,000	825,000
Repayment of Bank Credit Facility	—	(1,080,000)	(625,000)
Deferred financing costs	—	(32,872)	(11,775)
Other deferred payments	(20,539)	(2,389)	(1,545)
Payments of finance lease	(19,589)	(17,834)	(16,306)
Purchase of treasury stock	(119,459)	(45,181)	(47,504)
Employee stock awards tax withholdings	(3,588)	(6,206)	(7,459)
Distribution to noncontrolling interest	(1,347)	—	—
Net cash provided by (used in) financing activities	(164,522)	436,119	85,411
Net increase (decrease) in cash, cash equivalents and restricted cash	224,558	78,433	91,854
Cash, cash equivalents and restricted cash:			
Balance, beginning of period	214,432	135,999	44,145
Balance, end of period	$ 438,990	$ 214,432	$ 135,999
Supplemental non-cash transactions:			
Capital expenditures included in accounts payable and accrued liabilities	$ 84,721	$ 85,550	$ 114,972
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 118,037	$ 130,841	$ 130,313

See accompanying notes.

TALOS ENERGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2025

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's activities are primarily concentrated in the Deepwater (i.e., water depths of more than 600 feet) area of the U.S. Gulf of America. 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

Tax Disclosures — In December 2023, the FASB issued an update intended to improve income tax disclosures primarily through expanded disclosure of income tax rate reconciliation items and disaggregation of income taxes paid by jurisdiction. The tabular rate reconciliation requires both percentages and dollars to be presented. This disclosure guidance became effective for annual reporting periods beginning after December 15, 2024. The Company adopted this guidance retrospectively in this Annual Report on Form 10-K for the year ended December 31, 2025, and the adoption of such guidance did not have a material impact on the Company's consolidated financial statements. See additional information in Note 12 — *Income Taxes*.

Recently Issued Accounting Standards Not Yet Adopted

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, 2025 and 2024, the Company had allowances of $17.7 million and $25.5 million, respectively, presented in "Accounts receivable, net" on the Consolidated Balance Sheets.

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

Commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded in earnings each period. Realized gains and losses on the settlement of commodity derivatives and changes in their unrealized gains and losses are reported in "Price risk management activities income (expense)" on the Consolidated Statements of Operations. The Company classifies cash flows related to derivative contracts based on the nature and purpose of the derivative. As the 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 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, asset retirement 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 "Impairment 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 were 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 Statements 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, 2025, 2024 and 2023.

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,		
	2025	2024	2023
Shell Trading (US) Company	35%	48%	54%
Exxon Mobil Corporation	23%	17%	**
Valero Energy Corporation	**	**	21%
Chevron Corporation	12%	**	**

** 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 Statements of Cash Flows (in thousands):

	Year Ended December 31,	
	2025	2024
Cash and cash equivalents	$ 362,809	$ 108,172
Restricted cash included in Other long-term assets	76,181	106,260
Total cash, cash equivalent and restricted cash	$ 438,990	$ 214,432

The decrease in restricted cash is a result of amounts being released from the escrow account upon the completion of certain P&A work.

Accounts Receivable

The following table provides the components of "Accounts receivable, net" as presented on the Consolidated Balance Sheets (in thousands):

	Year Ended December 31,	
	2025	2024
Trade	$ 166,793	$ 236,694
Joint interest	132,527	133,562
Other	23,738	34,002
Total accounts receivable, net	$ 323,058	$ 404,258

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 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 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 year ended December 31, 2023 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, 2023 were adjusted to exclude $65.1 million of general and administrative expenses. This information does not purport to be indicative of results of operations that would have occurred had the EnVen Acquisition occurred on January 1, 2022, nor is such information indicative of any expected future results of operations (in thousands, except for the per share data).

	Year Ended December 31, 2023
Revenue	$ 1,509,929
Net income (loss)	$ 217,537
Basic net income (loss) per common share	$ 1.74
Diluted net income (loss) per common share	$ 1.73

Asset Acquisitions

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 with $24.4 million of additional cash consideration paid periodically in installments beginning January 1, 2025 through April 1, 2026. The Company allocated $42.6 million to proved properties. The carrying amount for the deferred cash consideration of $4.0 million is included in “Other current liabilities” on the Consolidated Balance Sheets at December 31, 2025.

Acquisition of Incremental Working Interest in Monument Oil Discovery — On March 7, 2025, the Company completed the acquisition of an additional 8.3% non-operated working interest in the Monument Project for $14.8 million, substantially all of which was allocated to its proved properties. An additional aggregate $6.3 million of contingent payments will be recognized upon the achievement of certain milestones defined in the agreement.

Acquisition of Incremental Working Interest in Mississippi Canyon Blocks — On July 22, 2025, the Company completed the acquisition of an additional 75.2% and 50.0% working interest in U.S. Gulf of America Mississippi Canyon blocks 108 and 110, respectively (the “Amberjack Acquisition”), in the Deepwater area. Prior to the Amberjack Acquisition, the Company owned an interest in and operated these developed and producing blocks. The Company also acquired a controlling financial interest in SP 49 Pipeline LLC (“SP 49”) as part of the Amberjack Acquisition. The one-third equity interest in SP 49 not held by the Company is presented as “Noncontrolling interest” in the Company’s Consolidated Financial Statements. The $38.6 million cost of the Amberjack Acquisition, including $33.7 million of cash at closing, was primarily allocated to the Company’s proved properties.

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 a purchase price of $125.0 million plus customary reimbursements and adjustments, combined totaling approximately $142.0 million (the “TLCS Divestiture”). The TLCS Divestiture included 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 entitled Talos to certain contingent payments, of which $4.7 million was received during the year ended December 31, 2024. 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, 2025. A deferred payment of $12.5 million due in October 2025 has not been received and the Company determined there was significant doubt surrounding the collectability of such deferred payment. Accordingly, the Company derecognized the deferred payment, of which $8.9 million is reflected as an expense in “Other operating income (expense)” and $3.6 million is reflected as the reversal of imputed interest income in “Other income (expense)” on the Consolidated Statements of Operations for the year ended December 31, 2025.

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.

The fair value of the Company’s retained equity method investment in Talos Mexico was $107.6 million upon the closing of the 2023 Mexico Divestiture. Fair value was determined using the implied value of Talos Mexico, based on the transaction price from the 2023 Mexico Divestiture, an orderly market transaction. 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. The Company’s ceiling test computations resulted in an impairment of its U.S. oil and natural gas properties during the year ended December 31, 2025 of $454.5 million. No impairment charges were recorded during the years ended December 31, 2024 and 2023. At December 31, 2025, its ceiling test computation was based on SEC pricing of $65.37 per Bbl of oil, $3.61 per Mcf of natural gas and $19.22 per Bbl of NGLs.

Further ceiling test impairments could be recorded in the near term should the 12-month average trailing commodity prices decline as compared to the commodity prices used in prior quarters.

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, 2025, by the year in which such costs were incurred (in thousands):

		Year Ended December 31,			
	Total	**2025**	**2024**	**2023**	**2022 and Prior**
Acquisition United States	$ 400,677	$ —	$ 263,783	$ 136,894	$ —
Exploration United States	79,878	41,576	26,314	9,585	2,403
Total unproved properties, not subject to amortization	$ 480,555	$ 41,576	$ 290,097	$ 146,479	$ 2,403

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 the majority of these costs to be transferred to the amortization base within six years of December 31, 2025.

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,		
	2025	2024	2023
Finance lease costs - interest on lease liabilities	$ 11,193	$ 12,948	$ 14,476
Operating lease costs, excluding short-term leases[(1)]	4,192	4,207	4,883
Short-term lease costs[(2)]	151,379	100,895	117,132
Variable lease costs[(3)]	2,668	2,464	2,888
Variable and fixed sublease income	(1,586)	(1,436)	(482)
Total lease costs	$ 167,846	$ 119,078	$ 138,897

(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. The short-term operating lease costs incurred during the periods presented are not necessarily indicative of the Company's future short-term lease costs and obligations, as it routinely executes short-term contracts for the use of drilling rigs to support its drilling activities. Short-term lease costs for drilling rigs can vary significantly based on the timing of the drilling program. Market conditions can also contribute to the volatility and variability of short-term drilling rig lease costs.
(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):

	December 31, 2025	December 31, 2024
Operating leases:		
Operating lease assets	$ 9,214	$ 11,294
Current portion of operating lease liabilities	$ 3,657	$ 3,837
Operating lease liabilities	11,956	15,489
Total operating lease liabilities	$ 15,613	$ 19,326
Finance leases:		
Proved properties	$ 166,261	$ 166,261
Other current liabilities	$ 21,473	$ 19,589
Other long-term liabilities	90,169	111,641
Total finance lease liabilities	$ 111,642	$ 131,230

The table below presents the lease maturity by year as of December 31, 2025 (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
2026	$ 5,072	$ 30,782
2027	4,753	30,782
2028	4,610	30,782
2029	3,226	30,782
2030	1,223	12,826
Thereafter	135	—
Total lease payments	$ 19,019	$ 135,954
Imputed interest	(3,406)	(24,312)
Total lease liabilities	$ 15,613	$ 111,642

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

	Year Ended December 31,		
	2025	2024	2023
Weighted average remaining lease term:			
Operating leases	3.9 years	4.8 years	5.9 years
Finance leases	4.4 years	5.4 years	6.4 years
Weighted average discount rate:			
Operating leases	10.8%	10.7%	10.8%
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,		
	2025	2024	2023
Operating cash outflow from finance leases	$ 11,193	$ 12,948	$ 14,476
Operating cash outflow from operating leases	$ 5,830	$ 5,634	$ 6,318
ROU assets obtained in exchange for new operating lease liabilities(1)	$ —	$ 1,909	$ 12,971
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, 2025 and 2024, 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, 2025		December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
9.000% Second-Priority Senior Secured Notes	$ 614,058	$ 649,425	$ 611,135	$ 640,619
9.375% Second-Priority Senior Secured Notes	$ 612,131	$ 656,250	$ 610,264	$ 635,750

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. See Note 8 — *Debt* for the maturity dates of the Company's Senior Notes.

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,		
	2025	2024	2023
Net cash received (paid) on settled derivative instruments	$ 81,471	$ 4,710	$ (9,457)
Unrealized gain (loss)	23,984	(6,168)	90,385
Price risk management activities income (expense)	$ 105,455	$ (1,458)	$ 80,928

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, 2025:

Swap Contracts

Production Period	Settlement Index	Volumes	Swap Price
Crude oil:		*(Bbls)*	*(per Bbl)*
January 2026 – December 2026	NYMEX WTI CMA	8,197	$ 65.51
Natural gas:		*(MMBtu)*	*(per MMBtu)*
January 2026 – December 2026	NYMEX Henry Hub	28,671	$ 3.85

Two-Way Collar Contracts

Production Period	Settlement Index	Volumes	Floor Price	Ceiling Price
Crude oil:		*(Bbls)*	*(per Bbl)*	*(per Bbl)*
January 2026 – December 2026	NYMEX WTI CMA	11,997	$ 60.00	$ 68.25

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

	December 31, 2025			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas derivatives	$ —	$ 54,420	$ —	$ 54,420
Liabilities:				
Oil and natural gas derivatives	—	(6,708)	—	(6,708)
Total net asset (liability)	$ —	$ 47,712	$ —	$ 47,712

	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

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, 2025		December 31, 2024	
	Assets	Liabilities	Assets	Liabilities
Oil and natural gas derivatives:				
Current	$ 54,420	$ 6,708	$ 33,486	$ 6,474
Non-current	—	—	253	3,537
Total gross amounts presented on balance sheet	54,420	6,708	33,739	10,011
Less: Gross amounts not offset on the balance sheet	6,708	6,708	10,011	10,011
Net amounts	$ 47,712	$ —	$ 23,728	$ —

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, 2025 represent derivative instruments from eight 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, 2025 would have been $47.7 million.

Note 7 — Equity Method Investments

Talos Mexico

See Note 3 – *Acquisitions and Divestitures* for additional information on the deconsolidation of Talos Mexico. 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 no later than May of 2026 upon the satisfaction of customary closing conditions and the receipt of all regulatory approvals. As of December 31, 2025, Talos Mexico, which currently holds a 17.4% interest in the Zama Field, is owned 50.1% by the Company and 49.9% by Zamajal. See Note 14 — *Related Party Transactions* for additional information on Carso.

The carrying amount of the Company's investment in Talos Mexico was $112.4 million and $111.3 million as of December 31, 2025 and 2024, respectively. The carrying amount of the investment includes a $66.0 million positive basis difference, which will be amortized using the units-of-production method upon commencement of regular commercial production from the Zama Field.

Bayou Bend CCS LLC

In March 2024, the Company sold its entire CCS business inclusive of Bayou Bend CCS LLC ("Bayou Bend"). See Note 3 – *Acquisitions and Divestitures* for additional information on the TLCS Divestiture. During the year ended December 31, 2023, Chevron U.S.A. Inc. ("Chevron") made $8.6 million of contributions to Bayou Bend on the Company's behalf in accordance with an agreement executed in 2022. 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 gain during the year ended December 31, 2023 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.

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. Developing oil fields with partners involves certain operational risks - namely, disagreements over project management, reliance on the operator's capabilities, and high capital expenditures. An Integrated Project Team ("IPT") reporting to the Zama Unit Operating Committee, was formed in March 2023 to pool the talents and competencies of all companies participating in the development of the Zama Field. Even though an IPT exists, teamwork could remain a challenge. The Zama Unit Development Plan ("UDP") was approved by CNH in June 2023. 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. Availability of equipment and unexpected construction hurdles could delay the start of oil and gas production. 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. On December 31, 2025, operatorship of the Zama Unit was transferred from Petróleos Mexicanos to Harbour Energy.

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):

	Maturity Date	December 31, 2025	December 31, 2024
9.000% Second-Priority Senior Secured Notes	February 1, 2029	$ 625,000	$ 625,000
9.375% Second-Priority Senior Secured Notes	February 1, 2031	625,000	625,000
Bank Credit Facility	March 31, 2027	—	—
Total debt, before discount and deferred financing cost		1,250,000	1,250,000
Unamortized discount and deferred financing cost, net		(23,811)	(28,601)
Total debt		$ 1,226,189	$ 1,221,399

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, 2025.

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.

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.

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 August 4, 2025, the Company entered into the Borrowing Base Redetermination Agreement and Twelfth Amendment to Credit Agreement (the "Twelfth Amendment"). The Twelfth Amendment, among other things, (i) decreased both the borrowing base and commitments to $700.0 million and (ii) removed the $50.0 million cap on the amount of unrestricted cash that may be deducted in the calculation of consolidated total debt (used to calculate the Consolidated Total Debt to EDITDAX ratio under the Bank Credit Facility) if, as of the applicable date of determination, each lender's total exposure is $0.

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, 2025, the Company's borrowing base was $700.0 million with total commitments of $700.0 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 $250.0 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, 2025. See Note 15 — *Commitments and Contingencies* for the amount of letters of credit issued under the Bank Credit Facility as of December 31, 2025.

Subsequent Event — On January 20, 2026, Talos Energy Inc., Talos Production Inc., a Delaware corporation and wholly owned subsidiary of the Company ("Talos Production"), and certain other direct and indirect subsidiaries of the Company and Talos Production entered into the Amended and Restated Credit Agreement (the "A&R Credit Agreement") among the Company, Talos Production, as Borrower, JPMorgan Chase Bank, N.A., as administrative agent (the "Administrative Agent"), the issuing banks, the lenders party thereto, and the other persons from time to time party thereto. The A&R Credit Agreement amends and restates in its entirety the credit agreement, dated as of May 10, 2018 (as amended from time to time, the "Existing Credit Agreement"), by and among the Company, Talos Production, as Borrower, JPMorgan Chase Bank, N.A., as administrative agent, the issuing banks, the lenders party thereto, and the other persons party thereto.

This credit facility has an initial borrowing base and total commitments of $700.0 million (with a letter of credit facility with a $250 million sublimit), subject to redetermination by the lenders at least semi-annually during the second quarter and fourth quarter of each year. The maturity date of the A&R Credit Agreement is the earlier of (i) January 20, 2030 and (ii) November 2, 2028 (the 91st day prior to the earliest stated maturity date of the 9.000% Notes, (or any Permitted Refinancing Indebtedness with respect thereto)), if such notes (or such Permitted Refinancing Indebtedness) have not been refinanced, redeemed, or repaid in full on prior to such 91st day.

Interest accrues at Talos Production'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"). 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 and six-months) calculated and published by the CME Group Inc. The adjusted daily simple SOFR is equal to the overnight SOFR calculated and published by the Federal Reserve Bank of New York. In addition, Talos Production is obligated to pay a commitment fee on the unutilized portion of the commitments. The applicable margin and the commitment fee rate are calculated based upon the utilization levels as a percentage of unused lender commitments then in effect.

The A&R Credit Agreement includes certain conditions to borrowings, representations and warranties and events of default customary for financings of its type and size. The A&R Credit Agreement also limits the Company's, Talos Production's and their respective subsidiaries' ability to, among other things, incur additional indebtedness, grant liens on any assets, pay dividends or make certain restricted payments, make certain investments, consummate certain asset sales, make certain payments on indebtedness, and merge, consolidate or engage in other fundamental changes. The A&R Credit Agreement has certain customary affirmative and negative covenants, including that Talos Production must maintain a Consolidated Total Debt to EBITDAX Ratio (as defined in the A&R Credit Agreement) of no greater than to 3.00 to 1.00 calculated each quarter utilizing the most recent twelve months to determine EBITDAX. Talos Production must also maintain a current ratio no less than 1.00 to 1.00 each quarter. Under the A&R Credit Agreement, unutilized commitments are included in current assets in the current ratio calculation. This credit facility is secured by, among other things, mortgages covering at least 85.0% of the proved oil and natural gas assets of the Company and is fully and unconditionally guaranteed by the Company and certain of its wholly-owned subsidiaries.

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 equity method investee as of December 31, 2025 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, 2025, 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,	
	2025	2024
Balance, beginning of period	$ 1,149,735	$ 897,226
Obligations assumed[(1)]	10,868	199,519
Obligations incurred	14,146	107
Obligations settled	(117,847)	(108,789)
Obligations divested	(3,150)	—
Accretion expense	125,296	117,604
Changes in estimate[(2)]	153,080	44,068
Balance, end of period	$ 1,332,128	$ 1,149,735
Less: Current portion	112,489	97,166
Long-term portion	$ 1,219,639	$ 1,052,569

(1) Obligations assumed during the year ended December 31, 2024 were in connection with the QuarterNorth Acquisition. See further discussion in Note 3 — *Acquisitions and Divestitures*.
(2) Changes in estimate were primarily due to changes in expected timing and cost estimates to satisfy certain future abandonment obligations.

At December 31, 2025, the Company has (1) restricted cash of $76.2 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. The net proceeds from this equity offering partially funded the cash portion of the QuarterNorth Acquisition. See Note 3 – *Acquisitions and Divestitures* for additional information on the QuarterNorth Acquisition.

Note 11 — Employee Benefits Plans and Share-Based Compensation

Severance

During the years ended December 31, 2024 and 2023, the Company accrued severance costs of $26.0 million and $25.3 million, respectively, in connection with the EnVen Acquisition, QuarterNorth Acquisition and TLCS Divestiture. See Note 3 — *Acquisitions and Divestitures* for additional information. The involuntary termination benefits were provided pursuant to (i) a one-time benefit arrangement that was recognized over the future service period through the termination date and (ii) 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. The severance accrual had been reduced to an immaterial amount by December 31, 2024.

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, 2025 was approximately $31.5 million, which is expected to be recognized over a weighted average period of 1.8 years.

On September 9, 2024, there were 157,071 RSUs issued as retention awards to executive officers that were 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, 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	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	3,542,435	$ 12.83
Granted	3,017,967	$ 8.80
Vested	(1,484,838)	$ 13.46
Forfeited	(479,809)	$ 10.25
Unvested RSUs at December 31, 2025	4,595,755	$ 10.25

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, 2025 was approximately $6.9 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, 2022	638,601	$ 23.66
Granted[(1)]	595,394	$ 18.76
Forfeited	(217,346)	$ 21.28
Unvested PSUs at December 31, 2023	1,016,649	$ 21.30
Granted[(2)]	299,472	$ 11.36
Forfeited[(3)]	(666,455)	$ 22.71
Unvested PSUs at December 31, 2024	649,666	$ 15.27
Granted[(4)]	1,014,647	$ 9.87
Forfeited[(5)]	(550,014)	$ 15.94
Unvested PSUs at December 31, 2025	1,114,299	$ 10.02

(1) 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.

(2) 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.

(3) 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.

(4) There were 837,066 PSUs granted that are 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. The remaining PSUs granted are eligible to vest based on continued employment and the achievement of certain stock-price hurdles over a three-year performance period.

(5) The performance period for 317,494 PSUs ended on December 31, 2025. 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 2026. 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 during the periods indicated:

	Year Ended December 31,		
	2025	2024	2023
Expected term (in years)	2.3 - 2.8	2.2 - 2.3	2.1 - 2.8
Expected volatility	45.6 - 52.4%	49.5 - 54.4%	61.9 - 73.1%
Risk-free interest rate	3.5 - 3.8%	3.6 - 4.1%	4.4 - 4.6%
Dividend yield	— %	— %	— %

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 (used in) 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,		
	2025	2024	2023
Share-based compensation costs	$ 25,967	$ 22,088	$ 25,236
Less: Amounts capitalized to oil and gas properties	7,549	7,626	12,283
Total share-based compensation expense	$ 18,418	$ 14,462	$ 12,953

Note 12 — Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31, 2025	2024	2023
Current income tax expense (benefit):			
Federal	$ (140)	$ (2,180)	$ 18
State	739	103	58
Mexico	73	309	31
Total current income tax expense (benefit)	$ 672	$ (1,768)	$ 107
Deferred income tax expense (benefit):			
Federal	$ (94,409)	$ (10,874)	$ (61,182)
State	(15,432)	17,645	478
Mexico	—	—	—
Total deferred income tax expense (benefit)	$ (109,841)	$ 6,771	$ (60,704)
Total income tax expense (benefit)	$ (109,169)	$ 5,003	$ (60,597)

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, 2025		2024		2023	
Income tax expense (benefit) at the federal statutory tax rate	$ (126,944)	21.0 %	$ (14,992)	21.0 %	$ 26,614	21.0 %
State and local income taxes, net of federal benefit[(1)]	(14,849)	2.5 %	17,726	(24.8)%	524	0.4 %
Foreign tax effects						
Mexico						
Statutory tax rate difference between Mexico and U.S.	169	(0.0)%	295	(0.4)%	436	0.4 %
Other	(565)	0.1 %	(671)	0.9 %	(1,452)	(1.1)%
Change in valuation allowance	28,800	(4.8)%	—	— %	(93,726)	(74.0)%
Nontaxable or nondeductible items	2,848	(0.5)%	4,925	(6.9)%	4,419	3.5 %
Effect of cross-border tax laws	395	(0.1)%	620	(0.9)%	1,016	0.8 %
Change in unrecognized tax benefits	73	(0.0)%	65	(0.1)%	31	0.0 %
Other adjustments	904	(0.1)%	(2,965)	4.2 %	1,541	1.2 %
Total income tax expense (benefit)	$ (109,169)	18.1 %	$ 5,003	(7.0)%	$ (60,597)	(47.8)%
Effective tax rate	18.1 %		(7.0)%		(47.8)%	

(1) State and local taxes in Louisiana made up the majority (greater than 50%) of the tax effect in this category.

The Company's effective tax rate for the year ended December 31, 2025 differed from the federal statutory rate of 21.0% primarily due to recording an income tax expense of $28.8 million related to recording a valuation allowance on its U.S. federal deferred tax assets offset with a state income tax benefit of $14.8 million.

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 state income tax expense of $17.7 million and income tax expense of $4.9 million related to nontaxable or nondeductible items.

The Company's effective tax rate for the year ended December 31, 2023 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax benefit of $93.7 million related to the release of the valuation allowance for its federal deferred tax assets offset with income tax expense of $4.4 million related to nontaxable or nondeductible items.

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, 2025. Significant components of deferred tax assets and liabilities were as follows (in thousands):

	Year Ended December 31,	
	2025	2024
Deferred tax assets:		
Federal net operating loss	$ 139,330	$ 108,717
Foreign tax loss carryforward	544	452
State net operating loss	16,359	12,426
Interest expense carryforward	40,177	74,957
Asset retirement obligations	302,222	262,773
Finance lease liability	25,389	29,926
Other	19,286	25,347
Total deferred tax assets	543,307	514,598
Valuation allowance	(32,735)	(3,325)
Total deferred tax assets, net	$ 510,572	$ 511,273
Deferred tax liabilities:		
Oil and gas properties	$ 656,457	$ 772,439
Derivatives	10,851	5,411
Total deferred tax liabilities	667,308	777,850
Net deferred tax liability	$ (156,736)	$ (266,577)

Net Operating Loss

The table below presents the details of the Company’s net operating loss carryovers as of December 31, 2025 (in thousands):

	Amount	Expiration Year
Federal net operating losses	$ 263,501	2036 - 2037
Federal net operating losses	$ 399,976	Unlimited
Foreign tax loss carryforward	$ 1,812	2026 - 2035
State net operating losses	$ 373,383	Unlimited

As of December 31, 2025, the Company had U.S. federal net operating loss carryforwards (“NOLs”) of approximately $663.5 million, $569.8 million of which are subject to limitations 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 $32.7 million and $3.3 million as of December 31, 2025 and 2024, 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. At December 31, 2025, the Company’s valuation allowance primarily related to the temporary differences related to the Company’s asset retirement obligations. At December 31, 2024, the company’s valuation allowance related to state operating loss carryforwards.

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.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits.

Balances in the uncertain tax positions are as follows (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Total unrecognized tax benefits, beginning balance	$ 1,592	$ 989	$ 835
Increases in unrecognized tax benefits as a result of:			
Tax positions taken during a prior period	277	(120)	154
Tax positions taken during the current period	—	723	—
Total unrecognized tax benefits, ending balance	$ 1,869	$ 1,592	$ 989

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.

Income Taxes Paid

The components of income taxes paid (net of refunds) were as follows (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Income taxes paid (net of refunds)			
Federal (U.S.)	$ 179	$ 5,215	$ (18)
Louisiana	418	1	—
Other	34	(297)	12
Total income taxes paid (net of refunds)	$ 631	$ 4,919	$ (6)

Years Open to Examination

The 2022 through 2025 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.

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 attributable to common stockholders (in thousands, except for the per share amounts):

	Year Ended December 31,		
	2025	2024	2023
Net income (loss) attributable to Talos Energy Inc.	$ (494,290)	$ (76,393)	$ 187,332
Weighted average common shares outstanding — basic	175,136	175,605	119,894
Dilutive effect of securities	—	—	858
Weighted average common shares outstanding — diluted	175,136	175,605	120,752
Net income (loss) per share attributable to common stockholders:			
Basic	$ (2.82)	$ (0.44)	$ 1.56
Diluted	$ (2.82)	$ (0.44)	$ 1.55
Anti-dilutive potentially issuable securities excluded from diluted common shares	3,581	2,084	1,353

Note 14 — Related Party Transactions

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 equity offering in January 2024 as further described in Note 10 — *Stockholders' Equity*, Control Empresarial further increased its holding of the Company's outstanding stock and thereafter continued to purchase shares from time to time in the open market.

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 will 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 in aggregate more than 25.0% of the outstanding shares of any class of voting securities of the Company. However, pursuant to the Cooperation Agreement, Control Empresarial and the investor group are not required to sell any voting securities they own if the aggregate ownership exceeds 25.0% solely because the Company repurchases shares or takes another similar action that reduces the number of outstanding voting securities.

On December 8, 2025, the Company entered into an amendment to the Cooperation Agreement with Control Empresarial to extend the period of the Cooperation Agreement for an additional year, to December 16, 2026, but the agreement is subject to early termination upon the occurrence of certain events described in the Cooperation Agreement. Control Empresarial held approximately 25.8% of the Company's outstanding shares of common stock as of December 31, 2025 based on SEC beneficial ownership reports filed by Control Empresarial and the Company's total outstanding shares of common stock as of that date.

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, 2025, Carso owes the Company $2.8 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 $0.7 million related party receivable from various equity method investments as of December 31, 2025 and 2024, respectively. These amounts are reflected in "Accounts Receivable, net" 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.

During the year ended December 31, 2024, the Company settled long-standing litigation initiated in June 2019 involving the former President of EnVen, which was assumed as part of the EnVen Acquisition. The Company paid $14.4 million to satisfy the judgment, inclusive of legal fees and interest.

By virtue of the Company's acquisition of QuarterNorth, Talos is defending a lawsuit brought by a contractor concerning amounts allegedly owed for drilling operations at several locations in the Gulf of America. The lawsuit alleges that the contractor is entitled to certain statutory liens under Louisiana law. Talos disputes the contractor's lien and damages claims and is defending the suit aggressively. A trial date has not been set for this case. It is reasonably possible that a loss may be realized, with the range of loss between zero and approximately $22 million.

By virtue of the Company's acquisition of QuarterNorth, Talos is defending a lawsuit brought by plaintiffs ("Warrant Holders") that held warrants issued by QuarterNorth pursuant and subject to warrant agreements. Warrant Holders allege that the QuarterNorth board improperly reduced the value of the warrants, which diluted their ownership interest in QuarterNorth prior to its acquisition by Talos. Trial is scheduled for May 2026, in the Court of Chancery of the State of Delaware. It is reasonably possible that a loss may be realized, with the range of loss between zero and approximately $21 million.

Firm Transportation Commitments

The Company has firm transportation agreements in place with pipeline carriers for future transportation of oil and gas production. The Company is obligated to transport a minimum monthly oil and gas volumes or pay for any deficiencies for years 2026 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, 2025 (in thousands):

2026	$	7,356
2027		11,760
2028		14,191
2029		7,468
2030		3,173
Total	$	43,948

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, and removal of facilities in the U.S. Gulf of America.

As of December 31, 2025, 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, 2025, the Company had secured letters of credit issued under its Bank Credit Facility totaling $97.4 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.

On November 3, 2025, the Company entered into arrangements with its surety providers to establish limits on the amount of aggregate collateral that such surety providers can require the Company to post, with annual collateral funding commitments set forth in the table below. The arrangements also require the Company to spend a minimum amount on plugging and abandonment activities each year. For the three years commencing January 1, 2026 and for the subsequent two years commencing January 1, 2029, the Company is required to spend $90.0 million and $45.0 million on these activities on an annual basis, respectively.

The table below outlines the estimated collateral funding commitments under the arrangements as of December 31, 2025 (in thousands):

Period	Collateral Funding Commitments	
2026	$	41,704
2027		42,694
2028		43,199
2029		42,134
2030		35,240
Thereafter		46,776
Total	$	251,747

The collateral funding commitments may be secured by cash or letters of credit which will reduce the Company's liquidity. For the year ended December 31, 2025, we posted collateral of $40.1 million secured by letters of credit. Collateral funded with cash will be reflected as "Restricted cash" within the Consolidated Balance Sheets. The collateral funding commitments, and ultimately any posted cash collateral, will be reduced as plugging and abandonment activities are completed and underlying surety bonds are released.

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,		
	2025	2024	2023
Balance, beginning of period	$ 20,002	$ 15,564	$ 54,269
Additions	1,769	6,168	266
Obligations assumed	—	1,326	—
Changes in estimate	1,476	2,391	11,613
Settlements	(1,102)	(5,447)	(50,584)
Balance, end of period	$ 22,145	$ 20,002	$ 15,564
Less: Current portion	470	5,453	3,280
Long-term portion	$ 21,675	$ 14,549	$ 12,284

Although it is reasonably possible that the Company could receive state or federal decommissioning orders in the future or be notified of defaulting third parties in existing leases, the Company cannot predict with certainty, if, how or when such orders or notices will be resolved or estimate a possible loss or range of loss that may result from such orders. However, the Company could incur judgments, enter into settlements or revise its opinion regarding the outcome of certain notices or matters, and such developments could have a material adverse effect on its results of operations in the period in which the amounts are accrued and its cash flows in the period in which the amounts are paid.

Note 16 — Segment Information

The Company's operations were managed through two operating segments through March 18, 2024: (i) the Upstream Segment and (ii) the CCS Segment, both of which were reportable for the year ended December 31, 2024. The CCS Segment was divested in March 2024.

Prior to the divestment of the CCS Segment, corporate general and administrative expense included certain shared costs such as finance, accounting, tax, human resources, information technology and legal costs that were not directly attributable to each operating segment. These shared expenses were fully allocated to each operating segment. Segment accounting policies are the same as those described in Note 2 – *Summary of Significant Accounting Policies*

The chief operating decision maker ("CODM") is currently the President and Chief Executive Officer and Chief Financial Officer. The profit or loss metric used to evaluate segment performance is net income as reported in the Company's Consolidated Statements of Operations. Net income is used by the CODM to measure segment profit or loss, assess performance and make strategic capital resource allocations. 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 tables below.

The following tables present selected segment information for the periods indicated (in thousands):

Year Ended December 31, 2025	Upstream	Total
Revenues from external customers	$ 1,780,070	$ 1,780,070
Significant expenses:		
Direct operating and maintenance[(1)]	(526,839)	(526,839)
Workover[(1)]	(19,877)	(19,877)
Adjusted general and administrative expense[(2)]	(133,986)	(133,986)
Net cash received (paid) on settled derivative instruments	81,471	81,471
Interest expense	(163,381)	(163,381)
Other segment items:		
Other[(3)]	10,349	10,349
Depreciation, depletion and amortization	(1,056,281)	(1,056,281)
Impairment of oil and natural gas properties	(454,482)	(454,482)
Accretion expense	(125,296)	(125,296)
Mark-to-market derivative fair value gain (loss)	23,984	23,984
Equity-based compensation expense	(18,418)	(18,418)
Equity method investment income (loss)	(1,807)	(1,807)
Income tax benefit (expense)	109,169	109,169
Net income (loss)	(495,324)	$ (495,324)
Segment Expenditures	$ 617,575	$ 617,575

(1) Component of lease operating expense.
(2) Includes general and administrative expense less transaction expenses and equity-based compensation.
(3) Primarily includes interest income and other miscellaneous operating income offset by the derecognition of a deferred payment that was deemed uncollectible.

Year Ended December 31, 2024	Upstream	CCS[(1)]	Total
Revenues from external customers	$ 1,973,568	$ —	$ 1,973,568
Significant expenses:			
Direct operating and maintenance[(2)]	(492,123)	—	(492,123)
Workover[(2)]	(73,918)	—	(73,918)
Adjusted general and administrative expense[(3)]	(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[(4)]	(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[(5)]	—	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) Component of lease operating expense.
(3) 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.
(4) 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*.
(5) 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:			
Direct operating and maintenance[2]	(374,481)	—	(374,481)
Workover[2]	(15,140)	—	(15,140)
Adjusted general and administrative expense[3]	(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[4]	(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[5]	66,180	—	66,180
Equity method investment income (loss)	120	(12,229)	(12,109)
Gain (loss) on partial sale of equity investment[6]	—	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) Component of lease operating expense.
(3) 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.
(4) 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*.
(5) See further discussion in Note 3 — *Acquisitions and Divestitures* for additional information.
(6) 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.*

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

	Year Ended December 31,		
	2025	2024	2023
Segment Expenditures:			
Total reportable segments	$ 617,575	$ 621,284	$ 774,630
Change in capital expenditures included in accounts payable and accrued liabilities	829	29,423	(9,199)
Plugging & abandonment	(117,847)	(108,789)	(86,615)
Decommissioning obligations settled	(1,102)	(5,447)	(50,584)
Investment in Talos Mexico	(4,559)	(5,469)	—
Investment in CCS intangibles and equity method investees	—	(17,519)	(40,946)
Other deferred payments	(2,104)	(2,389)	(1,545)
Non-cash well equipment transfers	(15,837)	(3,412)	(27,731)
Other	4,950	1,232	3,424
Exploration, development and other capital expenditures	$ 481,905	$ 508,914	$ 561,434

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,		
	2025	2024	2023
Consolidated Entities:			
Proved properties	$ 10,621,012	$ 9,784,832	$ 7,906,295
Unproved oil and gas properties, not subject to amortization	480,555	587,238	268,315
Total oil and gas properties	11,101,567	10,372,070	8,174,610
Less: Accumulated DD&A	6,672,024	5,163,844	4,143,491
Net capitalized costs	$ 4,429,543	$ 5,208,226	$ 4,031,119
DD&A rate (Per Boe)	$ 30.51	$ 30.11	$ 27.23
Company's Share of Equity Investees:			
Unproved oil and gas properties, not subject to amortization	$ 62,528	$ 58,723	$ 56,579

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,		
	2025	2024	2023
Consolidated Entities:			
Property acquisition costs:			
Proved properties	$ 62,689	$ 1,085,324	$ 951,703
Unproved properties, not subject to amortization	—	380,129	249,688
Total property acquisition costs	62,689	1,465,453	1,201,391
Exploration costs	54,647	129,400	161,296
Development costs	618,441	602,607	805,148
Total costs incurred	$ 735,777	$ 2,197,460	$ 2,167,835
Company's Share of Equity Investees:			
Exploration costs	$ 3,805	$ 2,144	$ 290

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, 2025 and 2024 all proved reserves were estimated by Netherland, Sewell & Associates, Inc ("NSAI"), independent petroleum engineers and geologists. At December 31, 2023, 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, 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
Revision of previous estimates	3,944	15,826	(686)	5,896
Production	(24,065)	(46,122)	(2,782)	(34,534)
Acquisition of reserves	7,232	2,573	10	7,670
Extensions and discoveries	467	4,349	227	1,419
Total proved reserves at December 31, 2025	130,626	194,600	11,634	174,693
Total Proved Developed Reserves as of:				
December 31, 2023	98,225	141,823	9,957	131,819
December 31, 2024	108,479	175,139	12,733	150,402
December 31, 2025	101,031	156,420	9,644	136,745
Total Proved Undeveloped Reserves as of:				
December 31, 2023	12,590	38,048	2,016	20,947
December 31, 2024	34,569	42,835	2,132	43,840
December 31, 2025	29,595	38,180	1,990	37,948

During 2025, proved reserves decreased by 19.5 MMBoe primarily due to 34.5 MMBoe of production. This decrease was partially offset by the acquisition of reserves of 7.7 MMBoe in connection with the incremental working interests in the Monument Project and certain Mississippi Canyon blocks as discussed in Note 3 — *Acquisitions and Divestitures* as well as an increase of 5.9 MMBoe from revisions of previous estimates. The revisions were due to certain upward revisions for positive well performance primarily in the Katmai Field combined with the Lobster Field, and from the Venice and Lime Rock wells, which tie back to our Ram Powell facility. These upward revisions were partially offset by the derecognition of approximately 2.0 MMBoe of PUD reserves associated with our South Timbalier 308 Field in the Shelf (i.e., water depths up to 600 feet) area, resulting from a reassessment of the drilling and development plan following successful drilling at the Katmai Field.

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 the Monument Project 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 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 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.

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,		
	2025	2024	2023
Consolidated Entities:			
Future cash inflows	$ 9,465,575	$ 11,660,546	$ 9,425,055
Future costs:			
Production	(2,954,861)	(3,436,232)	(3,090,491)
Development and abandonment	(2,901,567)	(3,301,619)	(2,358,368)
Future net cash flows before income taxes	3,609,147	4,922,695	3,976,196
Future income tax expense	(519,461)	(845,894)	(589,413)
Future net cash flows after income taxes	3,089,686	4,076,801	3,386,783
Discount at 10% annual rate	(284,829)	(512,597)	(343,295)
Standardized measure of discounted future net cash flows	$ 2,804,857	$ 3,564,204	$ 3,043,488

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,		
	2025	2024	2023
Oil price per Bbl	$ 65.37	$ 75.51	$ 78.56
Natural gas price per Mcf	$ 3.61	$ 2.45	$ 2.75
NGL price per Bbl	$ 19.22	$ 21.91	$ 18.77

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,		
	2025	2024	2023
Consolidated Entities:			
Standardized measure, beginning of year	$ 3,564,204	$ 3,043,488	$ 4,368,448
Sales and transfers of oil, net gas and NGLs produced during the period	(1,232,936)	(1,406,150)	(1,065,814)
Net change in prices and production costs	(946,617)	(123,537)	(2,835,125)
Changes in estimated future development and abandonment costs	72,525	193,810	(19,877)
Previously estimated development and abandonment costs incurred	183,066	47,016	202,503
Accretion of discount	420,072	485,409	518,110
Net change in income taxes	252,340	(181,190)	357,321
Purchases of reserves	143,040	1,638,000	2,033,852
Extensions and discoveries	7,250	74,126	90,244
Net change due to revision in quantity estimates	403,358	(162,041)	(484,423)
Changes in production rates (timing) and other	(61,445)	(44,727)	(121,751)
Standardized measure, end of year	$ 2,804,857	$ 3,564,204	$ 3,043,488

Note 18 — Subsequent Events

Amended and Restated Credit Agreement

For additional information, see Note 8 — *Debt*.

Schedule I. Condensed Financial Information of Registrant

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

	Year Ended December 31, 2025	2024
ASSETS		
Current assets:		
Prepaid assets	$ —	$ 203
Other current assets	179	19
Total current assets	179	222
Other long-term assets:		
Investments in subsidiaries	2,321,449	3,006,909
Total assets	$ 2,321,628	$ 3,007,131
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 40	$ 333
Accrued liabilities	567	544
Other current liabilities	1,058	162
Total current liabilities	1,665	1,039
Long-term liabilities:		
Other long-term liabilities	151,979	246,387
Total liabilities	153,644	247,426
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, 2025 and 2024, respectively	—	—
Common stock; $0.01 par value; 270,000,000 shares authorized; 188,530,052 and 187,434,908 shares issued as of December 31, 2025 and 2024, respectively	1,885	1,874
Additional paid-in capital	3,296,643	3,274,626
Accumulated deficit	(918,400)	(424,110)
Treasury stock, at cost; 20,015,369 and 7,417,385 shares as of December 31, 2025 and 2024, respectively	(212,144)	(92,685)
Total stockholders' equity	2,167,984	2,759,705
Total liabilities and stockholders' equity	$ 2,321,628	$ 3,007,131

See accompanying notes.

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

	Year Ended December 31,		
	2025	2024	2023
Operating expenses:			
General and administrative expense	$ 3,605	$ 3,234	$ 2,708
Total operating expenses	3,605	3,234	2,708
Operating income (expense)	(3,605)	(3,234)	(2,708)
Other income (expense)	(1)	(1)	(1)
Equity earnings (loss) from subsidiaries	(585,315)	(83,986)	128,888
Net income (loss) before income taxes	(588,921)	(87,221)	126,179
Income tax benefit (expense)	94,631	10,828	61,153
Net income (loss)	$ (494,290)	$ (76,393)	$ 187,332

See accompanying notes.

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

	Year Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net cash provided by (used in) operating activities	$ (1,399)	$ (1,403)	$ (1,836)
Cash flows from investing activities:			
Investments in subsidiaries	—	(389,138)	—
Distributions from subsidiaries	120,858	48,005	49,340
Net cash provided by (used in) investing activities	120,858	(341,133)	49,340
Cash flows from financing activities:			
Issuance of common stock	—	387,717	—
Purchase of treasury stock	(119,459)	(45,181)	(47,504)
Net cash provided (used in) by financing activities	(119,459)	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, 2025

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.

Exhibit 10.29

<u>FIRST AMENDMENT TO</u>
<u>EQUITY INTEREST PURCHASE AGREEMENT</u>

This FIRST AMENDMENT TO EQUITY INTEREST PURCHASE AGREEMENT (this "***Amendment***"), dated as of June [●], 2025 is entered into by and between (i) Talos Energy LLC, a Delaware limited liability company ("***TE***"), (ii) Talos Production Inc., a Delaware corporation ("***Talos***" or "***Seller***") and (iii) ZAMAJAL, S.A. DE C.V., a Mexican company ("***Grupo Carso***" or "***Purchaser***"). TE, Seller and Purchaser may each sometimes be referred to individually in this Agreement as a "***Party***," and collectively as the "***Parties***."

RECITALS

WHEREAS, TE, Seller and Purchaser are parties to that certain Equity Interest Purchase Agreement dated December 16, 2024, (as may be further amended, restated, supplemented or modified from time to time, the "***EPSA***");

WHEREAS, Section 9.2 of the EPSA provides that the EPSA may be amended or modified by a written agreement signed by the Parties; and

WHEREAS, TE, Seller and Purchaser wish to amend the EPSA on the terms set forth in this Amendment.

NOW, THEREFORE, in consideration of the foregoing premises and the agreements, provisions and covenants herein contained, the parties hereto agree as follows:

1.1 <u>Defined Terms and Rules of Interpretation</u>. Except as otherwise expressly provided herein, capitalized terms used herein which are not defined herein shall have the meanings set forth in the EPSA after giving effect to this Amendment. For all purposes of this Amendment, except as otherwise expressly provided or unless the context otherwise requires, the rules of construction set forth in Section 1.2 of the EPSA are hereby incorporated by reference, *mutatis mutandis*, as if fully set forth herein.

1.2 <u>Amendments</u>.

1.2.1<u>Preliminary Statements</u>. Paragraph E of the Preliminary Statements of the EPSA is hereby amended and restated in its entirety to read as follows:

> E. Purchaser desires to purchase from Seller and Seller desire to sell to Purchaser a portion of the Seller Equity representing a thirty and one tenth (30.10%) Equity Interest in the Holding Company represented by one equity quota with Mex$782,490,435.00 par value representing the variable portion of the stated capital of the Holding Company (the "***Equity***") upon the terms and subject to the conditions contained in this Agreement.

1.2.2<u>Sale and Purchase of the Equity</u>. Section 2.1 and Section 2.2 of the EPSA are hereby amended and restated in its entirety to read as follows:

ARTICLE II

SALE AND PURCHASE OF THE EQUITY; CLOSING

Section 2.1 Sale and Purchase of the Equity . On the terms and subject to the conditions contained in this Agreement, at the Closing Seller shall sell to Purchaser, and Purchaser shall purchase from Seller, all of Seller's right, title, and interest in and to the Equity, with full title guaranty, free and clear of all Liens (other than restrictions under applicable securities Laws, the Organizational Documents of Holding Company or pursuant to this Agreement).

Section 2.2 Purchase Price. The purchase price for the Equity shall be an amount equal to Forty Nine Million Six Hundred Sixty-Five Thousand Dollars (US$49,665,000) (the "***Purchase Price***"). Upon the terms and subject to the conditions of this Agreement, the Purchase Price shall be paid by Purchaser to Seller in cash in Dollars in accordance with this Article II by wire transfer of immediately available funds to a bank account in the United States specified in writing by Seller prior to the Closing ("***Payment Instructions***").

1.2.3 Deliveries by Seller. Sections 2.5(b) and 2.5(f) of the EPSA are hereby amended and restated in their entirety to read as follows:

(b) an executed copy of the minutes of the Company's partners meeting as of the Closing Date prepared by the secretary of Company evidencing the resignation of two (2) current Talos members of the board of managers of the Company in the form set forth in Exhibit A and the appointment of two (2) replacement Grupo Carso members of the board of managers of the Company;

(f) duly executed original short forms of transfer agreements evidencing the transfer of the Equity for Mexican Tax purposes; and

1.2.4 Deliveries by Purchaser. Sections 2.6(b) of the EPSA is hereby amended and restated in its entirety to read as follows:

(b) a copy of the last entry in the partners ledger (*libro especial de socios*) of the Holding Company providing for the transfer and conveyance of the Equity in favor of Purchaser, duly signed by the secretary of the board of managers of the Holding Company.

1.2.5 Purchaser Qualification. Section 4.4(b) of the EPSA is hereby amended and restated in its entirety to read as follows:

> Purchaser is not disqualified (and completing the transactions contemplated by this Agreement will not cause Purchaser to be disqualified) by any Law from owning the Equity, or indirectly owning Equity Interests and assets of the Company. To Purchaser's Knowledge, no fact or circumstance would hinder or impede a Governmental Authority, if required by any Law, from unconditionally approving, or allowing without modification or delay, the transactions contemplated by this Agreement.

1.2.6 Outside Date. Section 7.1(b) of the EPSA is hereby amended and restated in its entirety to read as follows:

> by either Seller or Purchaser, if the Closing has not occurred on or before [twelve (12)] months after the Execution Date (as such date may be extended by the mutual written consent of Seller and Purchaser, the "***Outside Date***"); *provided, further*, that the right to terminate this Agreement under this Section 7.1(b) shall not be available to a Party whose breach of or failure to perform any of its representations, warranties, covenants, or agreements contained in this Agreement has been the cause of or has resulted in the failure of the Closing to occur on or prior to the Outside Date;

1.3 Effect on the EPSA. Upon and following the date hereof, each reference to the EPSA in the PSA shall be deemed to refer to the EPSA as amended by this Amendment. Except as expressly set forth herein, (a) the EPSA is and shall remain unchanged and in full force and effect, and (b) nothing contained in this Amendment shall, by implication or otherwise, limit, impair, constitute a waiver of, or otherwise affect the rights and remedies of the parties to the EPSA or any other document, or shall alter, modify, amend or in any way affect any of the terms, conditions, obligations, covenants or agreements contained in the EPSA.

1.4 Entire Agreement. This Amendment and the EPSA (including the Exhibits and Schedules), contain the entire agreement between the Parties and supersede all prior agreements, arrangements, and understandings, written or oral, between the Parties relating to the subject matter of this Agreement.

1.5 Governing Law. Sections 9.13 and 9.14 of the EPSA shall apply hereto *mutatis mutandis*.

1.6 Counterparts. This Amendment may be signed in any number of counterparts, each of which is an original and all of which taken together shall constitute one and the same instrument.

[Remainder of page intentionally left blank.]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their duly authorized representatives as of the date first written above.

TALOS ENERGY LLC

By: /s/ William S. Moss III
Name: William S. Moss III
Title: Executive Vice President and General Counsel

TALOS PRODUCTION INC.

By: /s/ William S. Moss III
Name: William S. Moss III
Title: Executive Vice President and General Counsel

ZAMAJAL, S.A. DE C.V.

By: /s/ Arturo Spinola García
Name: Arturo Spinola García
Title: Attorney-in-Fact

Exhibit 10.30

SECOND AMENDMENT TO EQUITY INTEREST PURCHASE AGREEMENT

This SECOND AMENDMENT TO EQUITY INTEREST PURCHASE AGREEMENT (this "***Amendment***"), dated as of December 11, 2025 is entered into by and between (i) Talos Energy LLC, a Delaware limited liability company ("***TE***"), (ii) Talos Production Inc., a Delaware corporation ("***Talos***" or "***Seller***") and (iii) ZAMAJAL, S.A. DE C.V., a Mexican company ("***Grupo Carso***" or "***Purchaser***"). TE, Seller and Purchaser may each sometimes be referred to individually in this Agreement as a "***Party***," and collectively as the "***Parties***."

RECITALS

WHEREAS, TE, Seller and Purchaser are parties to that certain Equity Interest Purchase Agreement dated December 16, 2024, (as may be further amended, restated, supplemented or modified from time to time, the "***EPSA***");

WHEREAS, Section 9.2 of the EPSA provides that the EPSA may be amended or modified by a written agreement signed by the Parties; and

WHEREAS, TE, Seller and Purchaser wish to amend the EPSA on the terms set forth in this Amendment.

NOW, THEREFORE, in consideration of the foregoing premises and the agreements, provisions and covenants herein contained, the parties hereto agree as follows:

1.1 Defined Terms and Rules of Interpretation. Except as otherwise expressly provided herein, capitalized terms used herein which are not defined herein shall have the meanings set forth in the EPSA after giving effect to this Amendment. For all purposes of this Amendment, except as otherwise expressly provided or unless the context otherwise requires, the rules of construction set forth in Section 1.2 of the EPSA are hereby incorporated by reference, *mutatis mutandis*, as if fully set forth herein.

1.2 Outside Date Amendment. Section 7.1(b) of the EPSA is hereby amended and restated in its entirety to read as follows:

> by either Seller or Purchaser, if the Closing has not occurred on or before May 12, 2026 (as such date may be extended by the mutual written consent of Seller and Purchaser, the "***Outside Date***"); *provided, further*, that the right to terminate this Agreement under this Section 7.1(b) shall not be available to a Party whose breach of or failure to perform any of its representations, warranties, covenants, or agreements contained in this Agreement has been the cause of or has resulted in the failure of the Closing to occur on or prior to the Outside Date;

1.3 Effect on the EPSA. Upon and following the date hereof, each reference to the EPSA in the PSA shall be deemed to refer to the EPSA as amended by this Amendment. Except as expressly set forth herein, (a) the EPSA is and shall remain unchanged and in full force and effect, and (b) nothing contained in this Amendment shall, by implication or otherwise, limit, impair, constitute a waiver of, or otherwise affect the rights and remedies of the parties to the EPSA or any other document, or shall alter, modify, amend or in any way affect any of the terms, conditions, obligations, covenants or agreements contained in the EPSA.

1.4 Entire Agreement. This Amendment and the EPSA (including the Exhibits and Schedules), contain the entire agreement between the Parties and supersede all prior agreements, arrangements, and understandings, written or oral, between the Parties relating to the subject matter of this Agreement.

1.5 Governing Law. Sections 9.13 and 9.14 of the EPSA shall apply hereto *mutatis mutandis*.

1.6 Counterparts. This Amendment may be signed in any number of counterparts, each of which is an original and all of which taken together shall constitute one and the same instrument.

[Remainder of page intentionally left blank.]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their duly authorized representatives as of the date first written above.

TALOS ENERGY LLC

By: /s/ William S. Moss III
Name: William S. Moss III
Title: Executive Vice President and General Counsel

TALOS PRODUCTION INC.

By: /s/ William S. Moss III
Name: William S. Moss III
Title: Executive Vice President and General Counsel

ZAMAJAL, S.A. DE C.V.

By: /s/ Arturo Spinola García
Name: Arturo Spinola García
Title: Attorney-in-Fact

Exhibit 21.1

TALOS ENERGY INC. - LIST OF SUBSIDIARIES*

Company Name	Jurisdiction of Incorporation
Talos Energy LLC	Delaware
Talos Energy Offshore LLC	Delaware
Talos Energy Operating Company LLC	Delaware
Talos Energy Phoenix LLC	Delaware
Talos Energy Ventures LLC	Delaware
Talos ERT LLC	Delaware
Talos Exploration LLC	Delaware
Talos Oil & Gas LLC	Delaware
Talos Petroleum LLC	Delaware
Talos Production Finance Inc.	Delaware
Talos Production Inc.	Delaware
Talos QN Exploration LLC	Delaware
Talos Resources LLC	Delaware
Talos Third Coast LLC	Delaware

* Each of the named subsidiaries is not necessarily a "significant subsidiary" as defined in Rule 1-02(w) of Regulation S-X, and Talos has several additional subsidiaries not named above. The unnamed subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" at the end of the year covered by this report.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-231925) of Talos Energy Inc. and in the related Prospectus;

(2) Registration Statement (Form S-3 No. 333-248754) of Talos Energy Inc. and in the related Prospectus;

(3) Registration Statement (Form S-3 No. 333-255489) of Talos Energy Inc. and in the related Prospectus;

(4) Registration Statement (Form S-3 No. 333-271232) of Talos Energy Inc. and in the related Prospectus;

(5) Registration Statement (Form S-3 No. 333-277867) of Talos Energy Inc. and in the related Prospectus;

(6) Registration Statement (Form S-3 No. 333-287526) of Talos Energy Inc. and in the related Prospectus;

(7) Registration Statement (Form S-8 No. 333-225058) pertaining to the Talos Energy Inc. Long Term Incentive Plan;

(8) Registration Statement (Form S-8 No. 333-256554) pertaining to the Talos Energy Inc. 2021 Long Term Incentive Plan; and

(9) Registration Statement (Form S-8 No. 333-281398) pertaining to the Amended and Restated Talos Energy Inc. 2021 Long Term Incentive Plan

of our reports dated February 24, 2026, with respect to the consolidated financial statements and the financial statement schedule of Talos Energy Inc. and the effectiveness of internal control over financial reporting of Talos Energy Inc. included in this Annual Report (Form 10-K) of Talos Energy Inc. for the year ended December 31, 2025.

/s/ Ernst & Young LLP

Houston, Texas
February 24, 2026

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We consent to (i) the inclusion in this Annual Report on Form 10-K of Talos Energy Inc. (the "Form 10-K") of our report dated January 29, 2026, containing information relating to Talos Energy Inc.'s estimated reserves as of December 31, 2025, and (ii) all references to our firm in the Form 10-K and to the incorporation by reference of said report in the Registration Statement on Form S-3 (File No. 333-231925), Registration Statement on Form S-3 (File No. 333-248754), Registration Statement on Form S-3 (File No. 333-255489), Registration Statement on Form S-3 (File No. 333-271232), Registration Statement on Form S-3 (File No. 333-287526), Registration Statement on Form S-3 (File No. 333-277867), Registration Statement on Form S-8 of Talos Energy Inc. (File No. 333-225058), Registration Statement on Form S-8 of Talos Energy Inc. (File No. 333-256554) and Registration Statement on Form S-8 of Talos Energy Inc. (File No. 333-281389).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr
Richard B. Talley, Jr
Chief Executive Officer

Houston, Texas
February 24, 2026

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Paul Goodfellow, certify that:

1. I have reviewed this Annual Report on Form 10-K of Talos Energy Inc. ("registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Paul Goodfellow

February 24, 2026

Paul Goodfellow
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Zachary B. Dailey, certify that:

1. I have reviewed this Annual Report on Form 10-K of Talos Energy Inc. ("registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

	/s/ Zachary B. Dailey
February 24, 2026	Zachary B. Dailey *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER AND
CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350**

Pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and in connection with the accompanying Annual Report on Form 10-K of Talos Energy Inc. (the "Company") for the year ended December 31, 2025 that is being filed concurrently with the Securities and Exchange Commission on the date hereof (the "Report"), Paul Goodfellow, Chief Executive Officer of the Company, and Zachary B. Dailey, Chief Financial Officer of the Company, each certify, to the best of his knowledge, that:

i. the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

ii. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2026

/s/ Paul Goodfellow
Paul Goodfellow
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Zachary B. Dailey
Zachary B. Dailey
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

January 29, 2026

Ms. Maria Pellacani
Talos Energy Inc.
333 Clay Street, Suite 3300
Houston, Texas 77002

Dear Ms. Pellacani:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the Talos Energy Inc. (Talos) interest in certain oil and gas properties located in Louisiana, Mississippi, Texas, and the Gulf of America. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Talos. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Talos's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Talos interest in these properties, as of December 31, 2025, to be:

	Net Reserves			Future Net Revenue[1] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	78,536.9	7,091.7	103,638.0	2,502,098.0	2,419,007.7
Proved Developed Non-Producing	22,494.8	2,551.6	52,782.6	420,826.4	438,502.9
Proved Undeveloped	29,594.7	1,990.3	38,179.8	686,222.8	331,526.8
Total Proved	130,626.4	11,633.6	194,600.5	3,609,147.2	3,189,037.4

Totals may not add because of rounding.

[1] Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Talos's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Talos's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2025. For oil and NGL volumes, the average West Texas Intermediate spot price of $66.01 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.387 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $65.37 per barrel of oil, $19.22 per barrel of NGL, and $3.611 per MCF of gas.

Operating costs used in this report are based on operating expense records of Talos. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for certain assets have been reduced by expenditure reimbursements, as allowed under production handling agreements. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. As requested, the field-level costs are allocated by month among the proved reserves categories based on the proportionate share of total proved future net revenue. Estimates of proved developed producing reserves and revenue are consequently dependent on Talos completing the proved drilling and workover programs scheduled in this report. Headquarters general and administrative overhead expenses of Talos are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Talos and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Talos's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the lease and well equipment. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Talos interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Talos receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Talos, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Talos, other interest owners, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Jose A. Aburto, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2018 and has over 9 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Jose A. Aburto
Jose A. Aburto, P.E. 146624
Vice President

Date Signed: January 29, 2026

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: January 29, 2026

JAA:NPD

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

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

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- (A) Costs of labor to operate the wells and related equipment and facilities.
- (B) Repairs and maintenance.
- (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
- (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
- (E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

- (A) The area identified by drilling and limited by fluid contacts, if any, and
- (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

- (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
- (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are

made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.