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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 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: 001-35512

AMPLIFY ENERGY CORP.

(Exact name of registrant as specified in its charter)

Delaware	**82-1326219**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 Dallas Street, Suite 1700, Houston, TX	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(832) 219-9001**

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	AMPY	NYSE

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definition 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 Exchange Act) Yes ☐ No ☑

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $101.0 million on June 30, 2025, based on $3.20 per share, the last reported sales price of the shares on the New York Stock Exchange on such date.

As of February 28, 2026, the registrant had 41,265,055 outstanding shares of common stock, $0.01 par value per share.

Documents Incorporated By Reference**:** Portions of the registrant's definitive proxy statement relating to its 2026 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2025, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Form 10-K.

AMPLIFY ENERGY CORP.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

3-D seismic: Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous Reservoir: Analogous reservoirs, as used in resource 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, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

API Gravity: The American Petroleum Institute's system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

Basin: A large depression on the earth's surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

Boe/d: One Boe per day.

BOEM: Bureau of Ocean Energy Management.

BSEE: Bureau of Safety and Environmental Enforcement.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one-degree Fahrenheit.

CO_2: Carbon dioxide.

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.

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Project: A development project is the means by which petroleum resources are brought to the status of economically producible. Examples include 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.

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

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry Hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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. For this determination, the value of the products that generate revenue is determined at the terminal point of oil and natural gas producing activities.

Exploitation: A development or other project which may target proven or unproven reserves (such as probable or possible reserves) but which generally has a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

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. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

GAAP: Generally accepted accounting principles in the United States of America.

Gross Acres or ***Gross Wells***: The total acres or wells, as the case may be, in which we have a working interest.

ICE: Inter-Continental Exchange.

MBbl: One thousand Bbls.

MMBbls: One million stock tank barrels.

MBoe: One thousand barrels of oil equivalent.

MBoe/d: One thousand barrels of oil equivalent per day.

MMBoe: One million barrels of oil equivalent.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

Net Acres or ***Net Wells***: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

Net Production: Production that is owned by us less royalties and production due others.

Net Revenue Interest: A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

NYSE: New York Stock Exchange.

Oil: Oil and condensate.

Operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Plugging and abandonment*:* Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues or ***PV-9***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 9% in accordance with the guidelines of the SEC.

Present value of future net revenues or ***PV-10***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

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 occurrences.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: 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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation, and the potential exists for an associated natural 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. Reserves that can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-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.

Proved Undeveloped Reserves ("PUDs"): Proved oil and natural gas 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved 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 tests in the area and in the same reservoir.

Realized Price: The cash market price less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

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.

Reserve Life: A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year end by production volumes. In our calculation of reserve life, production volumes are adjusted, if necessary, to reflect property acquisitions and dispositions.

Reserves: Reserves are estimated remaining quantities of oil and natural 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 natural gas or related substances to market and all permits and financing required to implement the project. 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).

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

Resources: Resources are quantities of oil and natural 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 unrecoverable. Resources include both discovered and undiscovered accumulations.

SEC: The U.S. Securities and Exchange Commission.

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

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 ("FASB") (using prices and costs in effect as of the date of estimation), less estimated future development, production and income tax expenses and discounted at 10% per annum to reflect the timing of future net revenue. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in our oil and natural gas properties. Standardized measure does not give effect to derivative transactions.

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

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and generally requires the owner to pay a share of the costs of drilling and production operations.

Workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate.

NAMES OF ENTITIES

As used in this 2025 Annual Report on Form 10-K (this "Annual Report"), unless we indicate otherwise:

- "Amplify Energy," "Amplify," "Company," "we," "our," "us," or like terms refers to Amplify Energy Corp. individually and collectively with its subsidiaries, as the context requires;
- "Legacy Amplify" refers to Amplify Energy Holdings LLC (f/k/a Amplify Energy Corp.), the successor reporting company of Memorial Production Partners LP; and
- "OLLC" refers to Amplify Energy Operating LLC, the Company's wholly owned subsidiary through which it operates its properties.

FORWARD–LOOKING STATEMENTS

This Annual Report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategies;
- marketing of oil, natural gas and NGLs;
- acquisition and disposition strategy;
- cash flows and liquidity;
- financial strategy;
- ability to replace the reserves we produce through drilling;
- drilling locations;
- oil and natural gas reserves;
- technology;
- realized oil, natural gas and NGL prices;
- production volumes;
- lease operating expense;
- gathering, processing and transportation;
- general and administrative expense;
- future operating results;
- ability to procure drilling and production equipment;
- ability to procure oil field labor;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- ability to access capital markets;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns;
- acts of God, fires, earthquakes, storms, floods, other adverse weather conditions, war, acts of terrorism, cybersecurity breaches, military operations or national emergency;
- the occurrence or threat of epidemic or pandemic diseases, or any government response to such occurrence or threat;
- expectations regarding general economic conditions, including inflation;

- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- expectations regarding governmental regulation and taxation;
- expectations regarding developments in oil-producing and natural-gas producing countries; and
- plans, objectives, expectations and intentions.

All statements, other than statements of historical fact, included in this report are forward-looking statements. These forward-looking statements may be found in "Item 1. Business," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report. In some cases, you can identify forward-looking statements by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "outlook," "continue," the negative of such terms or other comparable terminology. These statements address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as projections of results of operations, plans for growth, goals, future capital expenditures, competitive strengths, references to future intentions and other such references. These forward-looking statements involve risks and uncertainties. Important factors that could cause the Company's actual results or financial condition to differ materially from those expressed or implied by forward-looking statements include, but are not limited to, the following risks and uncertainties:

- the concentration of the Company's properties in a limited number of geographic locations and the Company's dependence upon a small number of significant customers; including potential difficulties in the marketing of oil related to such small number of significant customers;
- the uncertainty inherent in the development and production of oil;
- the potential for additional impairments due to continuing or future declines in oil and NGL prices;
- volatility in the prices for oil and NGLs, including due to actions taken by the Organization of the Petroleum Exporting Countries (OPEC+) as it pertains to global supply and demand of, and prices for such commodities;
- the uncertainty inherent in estimating quantities of oil and NGL reserves;
- the existence of unanticipated liabilities or problems relating to acquired or divested businesses or properties;
- potential shortages of, or increased costs for, drilling and production equipment and supply materials for production, such as CO_2;
- the impact of local, state and federal governmental regulations, including those related to climate change and the current administration's potential reversal thereof;
- changes to the financial condition of counterparties;
- the impact of, and our ability to, remediate the identified material weaknesses in our internal controls over financial reporting;
- our ability to access funds on acceptable terms, if at all, due to potentially worsening economic conditions, including continued or further inflation, disruption in the financial markets, the imposition of tariffs or trade or other economic sanctions and political instability;
- the Company's substantial future capital requirements, which may be subject to limited availability of financing;

- the Company's need to make accretive acquisitions or substantial capital expenditures to maintain its declining asset base;
- potential acquisitions or dispositions, including the Company's ability to make acquisitions or dispositions on favorable terms;
- the consequences of changes the Company has made, or may make from time to time in the future, to its capital expenditure budget, including the impact of those changes on its production levels, reserves, results of operations and liquidity;
- the Company's ability to satisfy its debt obligations;
- uncertainties surrounding the success of the Company's secondary and tertiary recovery efforts;
- competition in the oil and natural gas industry;
- the Company's results of evaluation and implementation of strategic alternatives;
- general political and economic conditions, globally and in the jurisdictions in which we operate, including the Russian invasion of Ukraine and ongoing conflicts or entanglements in the Middle East and South America, trade wars and the potential destabilizing effect such conflicts or entanglements may pose for those regions and/or the global oil and natural gas markets;
- the impact of climate change and natural disasters, such as earthquakes, tidal waves, mudslides, fires and floods;
- the risk that the Company's hedging strategy may be ineffective or may reduce our income;
- risks related to a redetermination of the borrowing base under the Company's senior secured reserve-based revolving credit facility (the "Revolving Credit Facility");
- the Company's ability to access funds on acceptable terms, if at all, because of the terms and conditions governing its indebtedness, including financial covenants;
- the cost and availability of insurance as well as operating risks that may not be covered by an effective indemnity or insurance;
- actions of third-party co-owners of interest in properties in which we also own an interest or in which we may acquire an interest; and
- other risks and uncertainties described in "Item 1A. Risk Factors."

The forward-looking statements contained in this report are largely based on our expectations, which reflect estimates and assumptions made by the Company's management. These estimates and assumptions reflect the Company's best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond the Company's control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in "Item 1A. Risk Factors" and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on the Company's behalf.

RISK FACTOR SUMMARY

Our business is subject to numerous risks and uncertainties, including those highlighted in this section titled "Risk Factors" and summarized below. We have various types of risks, including risks related to our business and industry; information technology, data security and privacy; legal, regulatory, accounting, and tax matters; our common stock; and our Revolving Credit Facility, which are discussed more fully elsewhere in this Annual Report. As a result, this risk factor summary does not contain all of the information that may be important to you, and you should read this risk factor summary together with the more detailed discussion of risks and uncertainties set forth following this section under the heading "Risk Factors," as well as elsewhere in this Annual Report. These risks include, but are not limited to, the following:

- Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of oil and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.
- We are dependent upon a small number of significant customers for the majority of our production sales. The loss of those customers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition and results of operations.
- Our business could be adversely affected by a decline in general economic conditions or a weakening of the broader energy industry, and inflation may adversely affect our financial position and operating results.
- Our properties are concentrated in a limited number of geographic locations and adverse developments, including potential difficulties in the marketing of oil, in such operating areas could adversely affect our business, financial condition, results of operations and cash flows.
- The inability of our significant customers, vendors or other counterparties to meet their obligations to us may adversely affect our financial results.
- We are subject to, and in the future may be subject to additional complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.
- Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.
- The failure to replace our proved oil reserves could adversely affect our business, financial condition, results of operations, production and cash flows.
- Many of our properties are in areas that may have been partially depleted or drained.
- Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.
- We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.
- Restrictive covenants in our Revolving Credit Facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.
- Any failure to maintain effective internal control over financial reporting could impair the reliability of our financial statements, which in turn could harm our business, impair investor confidence in the accuracy and completeness of our financial reports and our access to the capital markets and cause the price of our Common Stock to decline and subject us to regulatory penalties.

- The operation of our business leverages IT infrastructure across our offices and facilities, and our business systems may (i) be susceptible to errors, shutdowns, sufficiency issues, or technical difficulties, (ii) experience security incidents impacting the integrity of sensitive data processed thereby, and (iii) be subject to evolving and potentially burdensome legal compliance requirements, including requirements around data privacy and security and the use of artificial intelligence technologies.

PART I

ITEM 1. BUSINESS

References

Amplify Energy Corp. ("Amplify Energy," "Amplify," the "Company," "we," "us," "our," or similar terms), is a publicly traded Delaware corporation, in which our common stock, par value of $0.01 per share ("Common Stock"), is listed on the NYSE under the symbol "AMPY."

Overview

Amplify Energy is an independent oil and natural gas company engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on one reportable business segment, as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries.

Our assets have historically consisted primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana, and the Eagle Ford (Non-op). During 2025, as discussed below, we completed several divestiture transactions, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisiana assets in December 2025, and our Oklahoma assets in December 2025. As a result of these divestitures, the oil and natural gas reserves presented herein reflect only properties owned as of December 31, 2025. As of the date of this Annual Report, our remaining properties consist solely of Bairoil and Beta.

As of the date of this Annual Report, the Company's properties consist of operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells. As of December 31, 2025:

- Our estimated proved reserves decreased to 38.1 MMBoe in 2025, primarily due to 53.2 MMBoe for divestitures reserves, changes in commodity prices, partially offset by upward reserves revisions due to performance, and reserve additions due to new locations specifically related to Beta;
- Our estimated proved reserves consisted of approximately 93% oil and 7% NGLs, and 65% were classified as proved developed reserves;
- We produced oil from 204 gross (204 net) producing wells across our properties, with an average working interest of 100%, and we are the operator of record of the properties containing 100% of our total estimated proved reserves; and
- Our average net production for the three months ended December 31, 2025, was 6.6 MBoe/d, implying a reserve-to-production ratio of approximately 15.9 years for Beta and Bairoil.

Recent Developments

Reduction in Force

During the fourth quarter of 2025 and throughout the first quarter of 2026, certain employees were impacted by a workforce reduction resulting in the involuntary termination of 36 employees across the Company. The Company recorded $6.8 million of severance expense for the year ended December 31, 2025, which is included in "general and administrative expense" in the Company's Consolidated Statement of Operations.

Amended Revolving Credit Facility

On December 31, 2025, OLLC entered into the Borrowing Base Redetermination, Commitment Increase and Second Amendment to Amended and Restated Credit Agreement (the "Second Amendment"), among OLLC, Amplify Acquisitionco LLC, the guarantors party thereto, the lenders party thereto and Citizens Bank, N.A., as administrative agent for the lenders. The Second Amendment amends the Amended and Restated Credit Agreement, dated July 31, 2023 (as amended, the "Credit Agreement"), to, among other things: (i) set the Borrowing Base to $25.0 million, with elected commitments of $15.0 million and (ii) extend the maturity date under the Credit Agreement to December 31, 2028. We had no amounts outstanding at December 31, 2025.

Revolution Purchase and Sale Agreement

On November 4, 2025, Amplify Oklahoma Operating LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Amplify Oklahoma"), Magnify Energy Services LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Magnify" and, together with Amplify Oklahoma, the "Revolution Sellers") and OLLC, for certain limited purposes, entered into a purchase and sale agreement (the "Revolution Purchase and Sale Agreement") with Revolution Resources III, LLC, a Delaware limited liability company ("Revolution"), pursuant to which the Revolution Sellers sold to Revolution certain assets of the Revolution Sellers, which include, among other things, the Revolution Sellers' right, title and interest in and to certain specified oil and gas properties and equipment within or related to certain designated lands in Oklahoma (the "Revolution Asset Sale") for a cash purchase price of $92.5 million, subject to estimated post-closing adjustments under the Revolution Purchase and Sale Agreement. The Revolution Asset Sale closed on December 29, 2025, with an effective date of October 1, 2025. We received net proceeds of $88.7 million from the Revolution Asset Sale. The proceeds from the divestiture were used to reduce borrowings under our Revolving Credit Facility. In connection with this transaction, we performed an assessment of the fair value of the net book value and determined that the assets were impaired, and as such, we recorded impairment expense of $34.0 million to write down those assets to the estimated purchase price less cost to sell.

EQV Purchase and Sale Agreement

On October 28, 2025, OLLC and Magnify (together with OLLC, the "EQV Sellers"), entered into a purchase and sale agreement (as subsequently amended, the "EQV Purchase and Sale Agreement") with EQV Alpha LLC, a Delaware limited liability company ("Alpha"), pursuant to which the EQV Sellers sold to Alpha certain assets of the EQV Sellers, which include, among other things, the EQV Sellers' right, title and interest in and to certain specified oil and gas properties and equipment within or related to certain designated lands in East Texas and Louisiana (the "EQV Asset Sale") for a cash purchase price of $122.0 million, subject to estimated post-closing adjustments under the EQV Purchase and Sale Agreement. The EQV Asset Sale closed on December 23, 2025, with an effective date of October 1, 2025. We received net proceeds of $111.6 million from the EQV Asset Sale. The proceeds from the divestiture were used to reduce borrowings under our Revolving Credit Facility.

East Texas Haynesville Monetization

On October 2, 2025, the Company entered into a purchase and sale agreement to sell its remaining interest in certain units with rights in the Cotton Valley and Haynesville basins in Harrison County, Texas, generating $5.3 million in net proceeds from the transactions. The sale closed on October 24, 2025, with an effective date of October 1, 2025.

Other 2025 Developments

Other 2025 Divestitures

In July 2025, we closed a transaction to divest our non-operated Eagle Ford assets for a total purchase price of $23.0 million, excluding $1.9 million of final post-closing adjustments, resulting in a final adjusted purchase price of $21.1 million. In connection with this transaction, we performed an assessment of the fair value of the net book value and determined that the assets were impaired, and as such, we recorded impairment expense of $8.4 million to write down those assets to the estimated purchase price less cost to sell.

Throughout 2025, we had other divestitures where we sold certain rights and interests in the Cotton Valley and Haynesville basins generating approximately $7.8 million in net proceeds from such transactions.

Leadership Changes

On July 21, 2025, the Company, and Mr. Martyn Willsher, the Company's former President, Chief Executive Officer and member of the Company's board of directors (the "Board"), agreed that (i) Mr. Willsher's roles as President and Chief Executive Officer of the Company and a member of the Board terminated effective July 22, 2025 (the "Transition Date"), and (ii) Mr. Willsher assumed the non-executive employee role of Special Advisor to the Company on the Transition Date.

In connection with the transition of Mr. Willsher's role, the Company and Mr. Willsher entered into a Transition and Separation Agreement (the "Transition Agreement"), effective as of the Transition Date. Pursuant to the terms of the Transition Agreement, Mr. Willsher served as Special Advisor to the Company until December 31, 2025.

Appointment of Chief Executive Officer and Director

On July 21, 2025, the Board appointed Mr. Daniel Furbee, previously the Company's Senior Vice President and Chief Operating Officer, to Chief Executive Officer and as a member of the Board, effective as of the Transition Date. In connection with Mr. Furbee's appointment as Chief Executive Officer, Mr. Furbee and the Company entered into a performance-based restricted stock units award agreement.

Appointment of President and Chief Financial Officer

On July 21, 2025, the Board appointed Mr. James Frew, previously the Company's Senior Vice President and Chief Financial Officer, to President and Chief Financial Officer, effective as of the Transition Date.

Appointment of Vice President and Chief Accounting Officer

On November 14, 2025, Mr. Eric Dulany and the Company mutually agreed Mr. Dulany's tenure as Vice President and Chief Accounting Officer would end, effective immediately. Mr. Dulany's departure did not result from any disagreement with the Company, the Company's management or the Board. On November 14, 2025, the Board appointed Ms. Natasha France, to serve as Vice President and Chief Accounting Officer of the Company, effective immediately.

Termination of Contemplated Merger with Juniper Capital

On January 14, 2025, the Company entered into an Agreement and Plan of Merger, as subsequently amended (the "Merger Agreement") with Amplify DJ Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of the Company ("First Merger Sub"), Amplify PRB Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of Amplify Energy ("Second Merger Sub"), North Peak Oil & Gas, LLC, a Delaware limited liability company ("NPOG"), Century Oil and Gas Sub-Holdings, LLC, a Delaware limited liability company ("COG" and, together with NPOG, the "Acquired Companies"), and, solely for the limited purposes set forth in the Merger Agreement, Juniper Capital Advisors, L.P. ("Juniper Capital") and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the effective time of the Contemplated Mergers (as defined below), it was contemplated that (i) NPOG would merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (ii) COG would merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement (clauses (i) and (ii), together, the "Contemplated Mergers").

On April 25, 2025, pursuant to Section 8.1(a) of the Merger Agreement, the Company and the Acquired Companies entered into a mutual termination agreement (the "Termination Agreement") to terminate the Merger Agreement (the "Termination"), effective immediately. As a result of the Termination Agreement, the Merger Agreement is of no further force and effect.

Industry Trends

We continue to monitor the impact of the actions of the Organization of the Petroleum Exporting Countries and other large producing nations; the Russia-Ukraine conflict; conflicts or entanglements in the Middle East and South America; global inventories of oil and natural gas and the uncertainty associated with recovering oil demand; inflation and future monetary policy; and governmental policies aimed at transitioning towards lower carbon energy. The Russia-Ukraine conflict and conflicts or entanglements in the Middle East and South America continue to evolve, and the extent to which these events may impact our business, results of operations, financial condition and cash flows will depend on future developments, which are highly uncertain and cannot be predicted with confidence.

Properties

As discussed above, our assets have historically consisted primarily of producing oil and natural gas properties in Oklahoma, Bairoil, Beta, East Texas/North Louisiana, and the Eagle Ford (Non-op). During 2025, we completed several divestiture transactions, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisiana assets in December 2025 and our Oklahoma assets in December 2025. As a result of these divestitures, the oil and natural gas reserves presented herein reflect only properties owned as of December 31, 2025. As of the date of this Annual Report, our remaining properties consist solely of Bairoil and Beta.

We engaged Cawley, Gillespie and Associates, Inc. ("CG&A"), our independent reserve engineers, to prepare our reserves estimates for all of our proved reserves at December 31, 2025. Accordingly, the proved oil and natural gas reserves presented herein reflect only those reserves attributable to properties owned as of December 31, 2025 and exclude reserves associated with properties divested during 2025. The following table summarizes information, based on a reserve report prepared by CG&A (which we refer to as our "reserve report"), about our proved oil reserves by geographic region as of December 31, 2025, and our average net production for the three months ended December 31, 2025:

	Estimated Net Proved Reserves			Average Net Production				
Region	MMBoe	% Oil and NGL	% Proved Developed	MBoe/d	% of Total	Average Reserve-to Production Ratio (1) (Years)	Producing Wells Gross	Producing Wells Net
Bairoil	13.7	100 %	100 %	2.9	44 %	13.0	152	152
Beta	24.3	100 %	45 %	3.7	56 %	18.3	52	52
Total	38.1	100 %	65 %	6.6	100 %	15.9	204	204

(1) The average reserve-to-production ratio is calculated by dividing estimated net proved reserves as of December 31, 2025 by the annualized average net production for the three months ended December 31, 2025. This calculation is based only on the Bairoil and Beta properties.

Our Areas of Operation

Beta

Approximately 64% of our estimated proved reserves as of December 31, 2025 and approximately 56% of our average daily net production for the three months ended December 31, 2025 were associated with the Beta field located in federal waters approximately 11 miles offshore from the Port of Long Beach, California. Our ownership in Beta consists of 100% of the working interests and 75.2% average net revenue interest in three Pacific Outer Continental Shelf lease blocks (P-0300, P-0301 and P-0306) (referred to as the "Beta Unit") in the Beta field. The Beta properties contained 24.3 MMBbls of estimated net proved oil reserves as of December 31, 2025 based on our reserve report and generated average net production of 3.7 MBoe/d for the three months ended December 31, 2025. Oil and gas are produced from the Beta Unit via two production platforms, referred to as the Ellen and Eureka platforms, equipped with permanent drilling rigs and associated equipment. On a third platform, Elly, the oil, water and gas are separated, and the oil is prepared for sale, while the gas is utilized as fuel for power and the water is recycled back into the reservoir for pressure maintenance. Sales quality oil is then pumped from the Elly platform to the Beta pump station located onshore at the Port of Long Beach, California via a 16-inch diameter oil pipeline, which extends approximately 17.5 miles. Amplify Energy's wholly owned subsidiary, San Pedro Bay Pipeline Company, owns and operates the pipeline system.

The following table summarizes production volumes from the Beta field for the period presented:

	For the Year Ended December 31,	
	2025	2024
Production Volumes:		
Oil (MBbls)	1,363	1,170
Total (MBoe)	1,363	1,170
Average net production (MBoe/d)	3.7	3.2

Bairoil

Approximately 36% of our estimated proved reserves as of December 31, 2025 and approximately 44% of our average daily net production for the three months ended December 31, 2025 were located in Bairoil. Our Bairoil properties include wells and properties primarily located in the Lost Soldier and Wertz fields in Wyoming at our Bairoil complex. Our Bairoil properties contained 13.7 MMBbls of estimated net proved oil and NGLs reserves as of December 31, 2025 based on our reserve report and generated average net production of 2.9 MBoe/d for the three months ended December 31, 2025.

The following table summarizes production volumes from Bairoil for the period presented:

	For the Year Ended December 31,	
	2025	2024
Production Volumes:		
Oil (MBbls) (1)	1,112	1,181
Total (MBoe)	1,112	1,181
Average net production (MBoe/d)	3.0	3.2

(1) NGLs are treated as condensate and are reflected within the oil line item above for all periods presented.

Our Oil and Natural Gas Data

Our Reserves

Internal Controls. Our proved reserves were estimated at the well or unit level for reporting purposes by CG&A, our independent reserve engineers. We maintain internal evaluations of our reserves in a secure reserve engineering database. CG&A interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting, and marketing employees to obtain the necessary data to prepare our proved reserves report. Reserves are reviewed and approved internally by our senior management on an annual basis and evaluated by our lender group on at least a semi-annual basis in connection with borrowing base redeterminations under our Revolving Credit Facility. Our reserve estimates are prepared by CG&A at least annually.

Our internal professional staff works closely with CG&A to ensure the integrity, accuracy and timeliness of data that is furnished to them in order to prepare the reserves report. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide CG&A with other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their preparation of our reserves.

Qualifications of Responsible Technical Persons

Internal Engineers. For the period covered by this Annual Report, Tony Lopez served as the technical person at the Company, primarily responsible for overseeing and providing oversight of the preparation of the reserves estimates with our third-party reserve engineers.

Mr. Lopez has over 20 years of corporate reserve reporting experience. Mr. Lopez joined the Company as Vice President of Corporate Reserves in June 2018 and for the period covered by this Annual Report has served as the Company's Senior Vice President of Engineering & Exploitation. Prior to June 2018, Mr. Lopez was Vice President of Acquisitions and Engineering for EnerVest, Ltd., where he managed the corporate reserve reporting process and the financial planning & analysis department. Mr. Lopez is a graduate of West Virginia University and holds a B.S. in Petroleum and Natural Gas Engineering. Mr. Lopez is an active member of the Society of Petroleum Engineers.

Cawley, Gillespie and Associates Inc. CG&A is an independent oil and natural gas consulting firm. No director, officer, or key employee of CG&A has any financial ownership in us or any of our affiliates. CG&A's compensation for the preparation of its report is not contingent upon the results obtained and reported. CG&A has not performed other work for us or any of our affiliates that would affect its objectivity. The estimates of our proved reserves presented in the CG&A reserve report were overseen by Todd Brooker.

Mr. Brooker became the President of CG&A in 2017 and has been an employee of CG&A since 1992. His responsibilities include reserve and economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. Prior to joining CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron Corporation. Mr. Brooker's experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures.

Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Estimated Proved Reserves

The following table summarizes our estimated proved oil and natural gas reserves and related standardized measure of discounted future net cash flows attributable to our properties as of December 31, 2025, which are based on the prepared reserve report by CG&A, our independent reserve engineers. The oil and natural gas reserves and related standardized measure disclosures presented herein are based on properties owned as of December 31, 2025 and are prepared in accordance with SEC regulations.

	Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe) (1)
Estimated Proved Reserves				
Developed	22,141	—	2,480	24,621
Undeveloped	13,475	—	—	13,475
Total	35,616	—	2,480	38,096
Proved developed reserves as a percentage of total proved reserves				65 %
Standardized measure (in thousands) (1)				$ 335,123
PV-10 (in thousands) (2)				$ 376,361
Oil and Natural Gas Prices (3)				
Oil – WTI ($ per Bbl)				$ 65.34
Natural gas – Henry Hub ($ per MMBtu)				$ 3.39

(1) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, *Extractive Activities—Oil and Gas*, and is calculated using SEC pricing, before market differentials, of $65.34 per Bbl for crude oil and NGLs. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest expense, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions. For a description of our commodity derivative contracts, see "Item 1. Business — Operations — Derivative Activities" as well as "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Commodity Derivative Contracts."

(2) PV-10 is a non-GAAP financial measure and represents the year end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC prescribed pricing assumptions for the period. PV-10 differs from standardized measure because standardized measure includes the effects of future income taxes on future net cash flows. Standardized measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing costs and discount assumptions. Amplify believes the presentation of PV-10 provides useful information because it is widely used by investors in evaluating oil and natural gas companies without regard to specific income tax characteristics of such entities. PV-10 is not intended to represent the current market value of our estimated proved reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(3) Our estimated net proved reserves and related standardized measure were determined using 12-month trailing average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month in effect as of the date of the estimate, without giving effect to derivative contracts, held constant throughout the life of the properties. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

The data in the table above represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate standardized measure, which is required by the SEC and FASB, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For these reasons, neither standardized measure nor PV-10 should be construed as the fair value of our oil and natural gas reserves.

For a discussion of risks associated with internal reserve estimates, see "Item 1A. Risk Factors — Risks Related to Our Business — Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves."

Development of Proved Undeveloped Reserves

As of December 31, 2025, we had 13,475 MBoe of PUDs, comprised of 13,475 MBbls of oil. None of our PUDs as of December 31, 2025 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

For the year ended December 31, 2025, total PUDs increased by 2,719 MBoe. The increase includes 2,294.7 MBoe due to the addition of 4 Beta PUD locations. We also had transfers of (3,263.5) MBoe to proved developed reserves which included 4 Beta PUD, 4 East Texas PUD and 15 Eagle Ford PUDs. We sold the remaining Eagle Ford PUD locations of (451) MBoe. Other revisions consisted of 4,139.2 MBoe that were primarily related to updated Beta PUD performance and extended economic life.

Approximately 30.3% (3,263.5 MBoe) of our PUDs recorded as of December 31, 2024, were developed during the twelve months ended December 31, 2025. Total costs incurred to develop these PUDs were approximately $49.9 million. In total, we incurred total capital expenditures of approximately $36.1 million during fiscal year 2025 developing PUDs. Based on our current expectations of our cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations, cash on hand and borrowings under our Revolving Credit Facility. For a more detailed discussion of our liquidity position, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Production, Revenue and Price History

For a description of our production, revenues, and average sales prices and per unit costs, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations."

The following tables summarize our average net production, average unhedged sales prices by product and average lease operating expense per Boe by geographic region for the years ended December 31, 2025 and 2024, respectively:

	For the Year Ended December 31, 2025								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma (1)	286	$ 64.49	446	$ 20.62	5,005	$ 3.24	1,566	$ 28.01	$ 10.03
Bairoil	1,112	59.25	—	—	—	—	1,112	59.25	45.67
Beta	1,363	60.41	—	—	—	—	1,363	60.41	38.12
East Texas/ North Louisiana (2)	120	64.10	602	19.63	10,836	3.27	2,528	21.70	7.92
Eagle Ford (3)	127	66.16	19	18.76	107	2.95	164	55.59	17.24
Total	3,008	$ 60.76	1,067	$ 20.03	15,948	$ 3.26	6,733	$ 38.03	$ 20.99
Average net production (MBoe/d)							18.4		

(1) The Oklahoma assets divestiture closed on December 29, 2025 with an effective date of October 1, 2025. As of the date of filing this Annual Report, we no longer operate in Oklahoma.
(2) The East Texas/North Louisiana divestiture closed on December 23, 2025 with an effective date of October 1, 2025. As of the date of filing this Annual Report, we no longer operate in East Texas/North Louisiana.
(3) The Eagle Ford divestiture closed on July 1, 2025 with an effective date of June 15, 2025. As of the date of filing this Annual Report, we no longer operate in the Eagle Ford.

	For the Year Ended December 31, 2024								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma	347	$ 75.05	525	$ 23.07	5,995	$ 2.06	1,871	$ 26.98	$ 8.53
Bairoil	1,181	70.01	—	—	—	—	1,181	70.01	44.70
Beta	1,170	72.51	—	—	—	—	1,170	72.51	38.94
East Texas/ North Louisiana	143	73.38	717	19.48	10,627	2.17	2,631	18.07	8.59
Eagle Ford	219	74.50	36	19.79	214	2.01	291	60.00	20.72
Total	3,060	$ 72.01	1,278	$ 20.96	16,836	$ 2.13	7,144	$ 39.61	$ 20.01
Average net production (MBoe/d)							19.5		

Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest and net wells are the sum of our fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2025.

	Oil	
	Gross	Net
Operated (1)	204	204
Non-operated	—	—
Total	204	204

(1) Our operated properties reflect all operated proved devolved producing properties at December 31, 2025.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2025, all of our leasehold acreage was held by production. The following table sets forth information as of December 31, 2025 relating to our leasehold acreage.

Region	Developed Acreage (1)	
	Gross (2)	Net (3)
Bairoil	6,653	6,653
Beta	17,280	17,280
Total	23,933	23,933

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.
(2) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(3) A net acre is deemed to exist when the sum of our fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

As of December 31, 2025, we had no gross and net undeveloped acreage expiring over the next two years as all of our gross and net acreage is currently held by production.

Drilling Activities

Our drilling activities primarily consist of development wells. The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2025, we had 0 gross (0 net) wells that were being developed.

	For the Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	26.0	5.9	11.0	2.0	9.0	0.5
Dry	—	—	—	—	—	—
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	26.0	5.9	11.0	2.0	9.0	0.5
Dry	—	—	—	—	—	—
Total	26.0	5.9	11.0	2.0	9.0	0.5

Delivery Commitments

We have no commitments to deliver a fixed and determinable quantity of our oil production in the near future under our existing sales contracts.

Operations

General

As of December 31, 2025, the Company is the operator of record of properties containing 100% of our total estimated proved reserves. We design and manage the development, recompletion and/or workover operations, and supervise other operation and maintenance activities for all of the wells we operate. We do not own the drilling rigs used for drilling wells on our onshore properties; independent contractors provide all the equipment and personnel associated with these activities. Our Beta platforms have permanent drilling systems in place.

Marketing and Major Customers

The following individual customers each accounted for 10% or more of our total reported revenues for the period indicated:

	For the Year Ended December 31,	
	2025	2024
Major customers:		
Phillips 66	28 %	33 %
HF Sinclair Corporation (formerly: Sinclair Oil & Gas Company)	21 %	25 %
Southwest Energy LP	n/a %	10 %

The production sales agreements covering our properties contain customary terms and conditions for the oil and natural gas industry and provide for sales based on prevailing market prices. A majority of those agreements have terms that renew on a month-to-month basis until either party gives advance written notice of termination.

If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether and we were unable to replace them, the loss of any such customer could have a detrimental effect on our production volumes and revenues in general.

On October 1, 2025, our agreement with Phillips 66 terminated following Phillips 66's closure of its Los Angeles-area refinery. Historically, prior to the termination of this agreement, this refinery represented a significant portion of our sales to Phillips 66. Following the termination of this agreement, we have entered into agreements with other customers for the sale of our Beta crude oil.

Title to Properties

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

Derivative Activities

We enter into commodity derivative contracts with unaffiliated third parties, generally lenders under our Revolving Credit Facility or their affiliates, to achieve more predictable cash flows and to reduce our exposure to fluctuations in oil and natural gas prices. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 25% − 75%, depending on availability under the Revolving Credit Facility, of our estimated production from total proved developed producing reserves over a one-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount.

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those in our Revolving Credit Facility) to fixed interest rates.

It is our policy to enter into derivative contracts only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our Revolving Credit Facility are counterparties to our derivative contracts. We will continue to evaluate the benefit of employing derivatives in the future.

Competition

We operate in a highly competitive environment for acquiring properties, leasing acreage, contracting for drilling equipment and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry and many of our competitors have access to capital at a lower cost than that available to us.

Hydraulic Fracturing

As discussed above, during 2025, we completed several divestiture transactions, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisiana assets in December 2025 and our Oklahoma assets in December 2025. Prior to such divestitures, hydraulic fracturing was used as a means to maximize the productivity of almost every well that we drilled and completed, except in our offshore wells. Hydraulic fracturing had been a necessary part of the completion process because our properties had historically been dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. As of December 31, 2025, none of the remaining proved reserves required hydraulic fracturing.

We believe we have followed and continue to substantially follow, where required and consistent with the standards previously reported, applicable industry standard practices and legal and regulatory requirements for groundwater protection in our previous hydraulic fracturing operations, which are subject to supervision by state and federal regulators (including the U.S. Bureau of Land Management (the "BLM") on federal acreage).

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, see "— Environmental, Occupational Health and Safety Matters and Regulations — Hydraulic Fracturing."

Insurance

In accordance with customary industry practice, we maintain insurance against many, but not all, potential losses or liabilities arising from our operations and at costs that we believe to be economic. We regularly review our risks of loss and the cost and availability of insurance and revise our insurance accordingly. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses. We currently have insurance policies that include the following:

- Commercial General Liability;
- Primary Umbrella / Excess Liability;
- Property;
- Workers' Compensation;
- Employer's Liability;
- Maritime Employer's Liability;
- U.S. Longshore and Harbor Workers';
- Energy Package/Control of Well;
- Loss of Production Income;
- Cybersecurity;
- Oil Pollution Act Liability;
- Pollution Legal Liability;
- Charterer's Legal Liability;
- Non-Owned Aircraft Liability;
- Automobile Liability;
- Directors & Officers Liability;
- Employment Practices Liability;
- Crime; and
- Fiduciary Liability.

We continuously monitor regulatory changes and comments and consider their impact on the insurance market, along with and our overall risk profile. As necessary, we will adjust our risk and insurance program to provide protection at a level we consider appropriate while weighing the cost of insurance against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations could lead to changes in underwriting standards, limitations on scope and amount of coverage, and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

Environmental, Occupational Health and Safety Matters and Regulations

General

Our oil and natural gas development and production operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, occupational health and safety aspects of our operations, or otherwise relating to protection of the environment and natural resources. These laws and regulations impose numerous obligations applicable to our operations, including the acquisition of certain permits before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; the suspension or revocation of necessary permits, licenses and authorizations; the requirement that additional pollution controls be installed; and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, in certain jurisdictions, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly owned or operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from our own actions that were in compliance with all applicable laws at the time such actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased in recent years. New laws and regulations continue to be enacted, particularly at the state level, and the long-term trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, which may result in increased costs of doing business and consequently affect profitability. To the extent new or more stringent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

The following is a summary of the more significant existing environmental, occupational health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our operations, capital expenditures, earnings or competitive position.

Offshore Operations

Our oil and gas operations associated with our Beta properties are conducted on offshore leases in federal waters, and those operations are regulated by agencies such as BOEM and BSEE, which have broad authority to regulate our oil and gas operations associated with our Beta properties.

BOEM is responsible for managing environmentally and economically responsible development of the nation's offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, and National Environmental Policy Act ("NEPA") analysis and environmental review. Lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of offshore operations. BOEM generally requires that lessees have substantial net worth, post supplemental bonds or provide other acceptable assurances that the obligations will be met. In October 2020, BOEM and BSEE issued a proposed rule to clarify, streamline, and provide greater transparency to financial assurance requirements for the oil and gas industry, including streamlining the evaluation criteria for determining if and when additional security is required for Outer Continental Shelf ("OCS") leases, pipeline rights-of-way and rights-of-use and easement ("RUE") and revising the process for issuing decommissioning obligations for facilities on the OCS. Pursuant to prior Executive Order 13990, BOEM decided not to move forward with the BOEM-administered portions, and instead issued a new notice of proposed rulemaking to address the financial policy concerns. BSEE finalized the BSEE-related provisions, which became effective on May 18, 2023, to focus on clarifying decommissioning obligations of RUE grant holders and promulgate BSEE policy regarding the obligations of predecessors that must decommission their units. In April 2024, BOEM published a final rule, effective June 2024, which modified criteria for determining whether oil, gas, and sulfur lessees, RUE grant holders, and pipeline right-of-way grant holders are required to provide bonds or other financial assurance above what is currently required to ensure compliance with OCS obligations. The final rule also codified the use of the BSEE's probabilistic estimates of decommissioning costs in setting the levels of demand for supplemental financial assurance, removed restrictive provisions for third-party guarantees and decommissioning accounts, and added new criteria for cancelling supplemental financial assurance. Litigation was filed challenging the BOEM 2024 rule, creating uncertainty regarding the finality of the BOEM 2024 rule requirements. On May 2, 2025, the U.S. Department of the Interior announced its intent to revise the BOEM 2024 rule and proceed with development of a new rule consistent with the 2020 proposed framework. In December 2025, the Western District Court of Louisiana issued a further stay of the litigation, pending BOEM's issuance of a new rule.

BSEE is responsible for safety and environmental oversight of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and training and environmental compliance programs. BSEE regulations require offshore production facilities and pipelines located on the OCS to meet stringent engineering and construction specifications, and in August 2023 and August 2024 BSEE announced two final rules which added safety-related regulations concerning the design and operating procedures of these facilities and pipelines, including regulations to safeguard against or respond to well blowouts and other catastrophes and manage equipment used in high pressure high temperature environments. In August 2025, BSEE issued a final rule to align with the One Big Beautiful Bill Act, which clarified expectations for offshore commingling, production methods for well integrity, safety and ultimate recovery. BSEE regulations also restrict the flaring or venting of natural gas, prohibit the flaring of liquid hydrocarbons and govern the plugging and abandonment of wells located offshore and the installation and removal of all fixed drilling and production facilities.

BOEM and BSEE have adopted regulations providing for enforcement actions, including civil penalties and lease forfeiture or cancellation for failure to comply with regulatory requirements for offshore operations. If we fail to pay royalties or comply with safety and environmental regulations, BOEM and BSEE may require that our operations on the Beta properties be suspended or terminated, and we may be subject to civil or criminal liability, which may have a negative impact on our operations, capital expenditures, earnings or competitive position.

In addition to permits and approvals required by BOEM and BSEE, approvals and permits may be required from other agencies for the oil and gas operations associated with our Beta properties, such as the U.S. Coast Guard, the EPA, U.S. Department of Transportation, U. S. Army Corps of Engineers and the South Coast Air Quality Management District.

Hazardous Substances and Waste Handling

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

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

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible that these wastes, which could include wastes currently generated during our operations, could be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes." Any such changes, including to state programs, could result in an increase in our costs to manage and dispose of oil and gas waste, which could have a material adverse effect on our maintenance capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials ("NORM"). NORM are present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes into contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with hazardous substance and waste handling requirements. We believe that we are in substantial compliance with the requirements of CERCLA, OPA, RCRA, and other applicable federal and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our hazardous substances and wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act"), the Safe Drinking Water Act ("SDWA"), the OPA and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and hazardous substances, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). In June 2015, the EPA and the Corps issued a rule to revise the definition of "waters of the United States" ("WOTUS") for all Clean Water Act programs, which never took effect before being replaced by the Navigable Waters Protection Rule (the "NWPR") in April 2020. The NWPR was vacated by two separate federal district courts in late 2021. The definition of WOTUS was further impacted by the U.S. Supreme Court's decision issued in May 2023 in Sackett v. EPA wherein the Court held that the jurisdiction of the Clean Water Act extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection and rejected the "significant nexus" test embraced in earlier jurisprudence. In September 2023, the EPA and the Corps published a direct-to-final rule redefining WOTUS to align with the decision in Sackett. The final rule eliminated the "significant nexus" test from consideration when determining federal jurisdiction and clarified that the Clean Water Act only extends to relatively permanent bodies of water and wetlands that have a continuous surface connection with such bodies of water. However, roughly half of the states and other plaintiffs are continuing to challenge the rule, and the EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. In November 2025, the Corps and the EPA issued a proposed rule revising the definition of WOTUS with the stated aim of conforming to the Supreme Court's decision in Sackett and revising certain regulatory terms, such as "relatively permanent," "tributary," and "continuous surface connection"; a final rule is expected in early 2026, and litigation is highly likely following issuance of the final rule. As a result, substantial uncertainty exists with respect to future implementation of the September 2023 rule and the scope of CWA jurisdiction more generally.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of storm water or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits or specify other requirements for discharges or operations that may impact groundwater conditions. These same regulatory programs may also limit the total volume of water that can be discharged, hence limiting the rate of development and requiring us to incur compliance costs. Additionally, we are required to develop and implement spill prevention, control and countermeasure plans, in connection with on-site storage of significant quantities of oil.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Additionally, obtaining permits has the potential to delay the development of oil projects. We maintain all required discharge permits necessary to conduct our operations and we believe we are in substantial compliance with their terms.

Hydraulic Fracturing

As discussed above, during 2025, we completed several divestiture transactions, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisianna assets in December 2025 and our Oklahoma assets in December 2025. Prior to such divestitures, hydraulic fracturing had been used as a means to maximize the productivity of almost every well that we drilled and completed, except in our offshore wells. Hydraulic fracturing was historically a necessary part of the completion process because certain of our properties were historically dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. As of the date of this Annual Report, we are no longer engaged in any current hydraulic fracturing operations.

During the period in which we historically utilized hydraulic fracturing in our operations, we believe we followed, where required and consistent with then-existing standards previously reported, applicable industry standard practices and legal and regulatory requirements for groundwater protection in our previous hydraulic fracturing operations, which are subject to supervision by state and federal regulators (including the BLM on federal acreage).

Air Emissions

The federal Clean Air Act, as amended ("CAA"), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. The South Coast Air Quality Management District ("SCAQMD") is a regulatory subdivision of the State of California and is responsible for air pollution control from stationary sources within Orange County and designated portions of Los Angeles, Riverside, and San Bernardino Counties. Our Beta properties and associated facilities are subject to regulation by the SCAQMD. Federal, SCAQMD, and other state laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants.

The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits.

In November 2021, the EPA issued a proposed rule intended to establish standards for methane and volatile organic compounds, or VOCs, from new and modified oil and natural gas production and natural gas processing and transmission facilities. The proposed rule sought to make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule sought to establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by EPA. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removed an emissions monitoring exemption for small wellhead-only sites and created a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters". The EPA announced a final rule in December 2023, later published in March 2024, which, among other things, requires the phase out of routine flaring of natural gas from new oil wells and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance dates under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane from existing sources. However, in March 2025, the EPA announced its intention to reconsider the March 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. A subsequent rule finalized on November 26, 2025, gives states, along with federal tribes that wish to regulate existing sources, until January 2027 to develop and submit their plans for reducing methane emissions from existing sources. In December 2025, environmental groups filed a petition for review in the D.C. Circuit Court of Appeals challenging the EPA's delay of the methane emissions rules.

Additionally, in 2016, the BLM finalized rules related to further controlling the venting and flaring of natural gas on BLM land, which was challenged by a group of states. In September 2018, the BLM published a final rule that revised the 2016 rules, which was again challenged by states and environmental groups. In April 2024, and later revised in November 2024, the BLM issued a final rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. In January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Legal challenges to the 2024 rule from various states has been held in abeyance throughout 2025, as BLM considers rule revisions. Through a direct final rule published in December 2025, the BLM has extended compliance deadlines for key components of the 2024 rule. Consequently, future implementation and enforcement of the final 2024 EPA rule and the final 2024 BLM rule remain uncertain at this time.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil projects and increase our costs of development, which costs could be significant. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Climate Change Regulation

At the international level, the United States joined the international community at the United Nations Framework Convention on Climate Change 21st Conference of the Parties ("COP21") in Paris, France in 2015, which resulted in an agreement intended to nationally determine their contributions and set greenhouse gas ("GHG") emission reduction goals every five years beginning in 2020. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement. The withdrawal became effective in January 2026. In January 2026, President Trump announced the United States will also withdraw from the UN Framework Convention on Climate Change. However, various state and local governments have publicly committed to furthering the goals of the Paris Agreement, and related initiatives are expected to continue. It is not possible at this time to predict how legislation or regulations that may be adopted to address climate change, methane and other GHG emissions may impact our business.

In August 2022, the prior Biden Administration signed into law the Inflation Reduction Act. The Inflation Reduction Act included a methane emissions reduction program that amended the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program required the EPA to impose a Waste Emissions Charge ("WEC") on certain oil and gas sources that are already required to report under EPA's Greenhouse Gas Reporting Program. To implement the program, in May 2024, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. The emissions reported under the Greenhouse Gas Reporting Program were set as the basis for any payments under the Methane Emissions Reduction Program. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. In addition, EPA proposed on September 12, 2025 to eliminate or suspend Greenhouse Gas Reporting Program requirements for most industries, with final rules implementing the proposed rollback expected by mid-2026. In November 2024, the EPA finalized a regulation to implement the Inflation Reduction Act's WEC. However, in January 2025, the Trump Administration issued an Executive Order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. In addition, in March 2025, President Trump signed Congress' Joint Resolution of Disapproval of the WEC, and in May 2025, EPA issued a final rule to remove the WEC regulations from the Code of Federal Regulations. In July 2025, the One Big Beautiful Bill Act delayed the effective date of the WEC until 2034.

The 2007 case Massachusetts v. EPA held that GHGs are air pollutants covered by the Clean Air Act, and that EPA must determine whether certain GHG emissions may reasonably be anticipated to endanger public health or welfare. In December 2009, EPA issued a final rule stating that current and projected concentrations of carbon dioxide, methane and other GHGs endanger public health and welfare ("2009 Endangerment Finding"). The 2009 Endangerment Finding served as legal support for subsequent EPA Clean Air Act rulemakings that have significantly affected industry operational costs, including New Source Performance Standards and Existing Source Guidelines rules requiring technology investments to detect and reduce methane leaks and emissions from new and existing oil and gas infrastructure. In the 2022 Supreme Court case West Virginia v. EPA, the Court held that EPA lacked clear statutory authority under the Clean Air Act, absent specific and explicit authorization from Congress, to implement an EPA rulemaking that mandated a shift for electricity production from higher greenhouse gas emissions sources to lower emissions sources. In the 2024 Supreme Court case Loper Bright Enters. v. Raimondo, the Court held that courts must independently determine the best reading of a statute, rather than deferring to agency interpretations of ambiguous statutory language. On February 12, 2026, EPA issued a pre-publication copy of a final rule, submitted for publication in the Federal Register, rescinding the 2009 Endangerment Finding on the basis that the 2009 Endangerment Finding exceeded EPA authority, was not supported by specific and explicit authorization from Congress, and did not meet the best reading of the underlying Clean Air Act provision under the West Virginia and Loper Bright holdings. Litigation following the February 2026 final rule publication is expected, and the potential impact of the February 2026 final rule, potential subsequent revisions to existing emission standards, and the outcome of related litigation, including private nuisance litigation, remain uncertain and could affect our operations.

At the state level, California enacted legislation in October 2023 that will ultimately require certain companies that do business in California and exceed specified financial thresholds to publicly disclose certain climate-related information, including their Scopes 1, 2, and 3 GHG emissions, with third party assurance of such data, climate-related financial risks and related mitigation measures. The California Air Resources Board has proposed that initial reporting for scope 1 and 2 GHG emissions for fiscal year 2025 be due by August 10, 2026, with Scope 3 GHG emissions reporting required in 2027. These laws are subject to ongoing legal challenges and certain requirements are currently enjoined. It is unclear how the litigation process and additional legal developments will impact enforceability of these requirements and the timeline and cost of compliance. While we are still assessing the impact of these requirements, additional reporting obligations could cause us to incur increased costs.

While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not currently adversely impacted by existing federal, state and local climate change initiatives. The adoption and implementation of any new regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Moreover, any legislation or regulatory programs to reduce GHG emissions could increase the cost of consumption, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. However, the Supreme Court's decision in Loper Bright Enterprises v. Raimondo to overrule Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc. ends the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs, and in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of federal climate change rules remain uncertain at this time.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to NEPA. NEPA requires federal agencies, including the U.S. Departments of the Interior and Agriculture, to evaluate major federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency evaluates the potential direct, indirect and cumulative impacts of a proposed project. If the proposed impacts are considered significant, the agency will prepare a detailed environmental impact statement that is made available for public review and comment. In July 2020, the White House's Council on Environmental Quality ("CEQ") published a final rule to amend the NEPA implementing regulations intended to streamline the environmental review process, including shortening the time for review as well as eliminating the requirement to evaluate cumulative impacts. The final rule required federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date (which was extended to two years in June 2021). In October 2021, the CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Phase I of the CEQ's proposed rulemaking process was finalized in April 2022, and generally restored provisions that were in effect prior to 2020. In May 2024, the CEQ finalized the Phase II rule that accelerates NEPA reviews while maintaining consideration of relevant environmental, environmental justice and climate change objectives. Further, the Infrastructure and Investment Jobs Act signed into law in November 2021 codified some of the July 2020 amendments in statutory text. These amendments must be implemented into each agency's implementing regulations, and each of those individual rulemakings could be subject to legal challenge. Additionally, in June 2023, the Fiscal Responsibility Act of 2023 was signed into law, which includes important changes to NEPA to streamline the environmental review process. However, in January 2025, President Trump issued an executive order requiring CEQ to provide guidance on implementing NEPA and to propose rescinding CEQ's NEPA regulations. The executive order also instructs federal agencies to adhere to only the relevant legislated requirements for environmental reviews and to prioritize efficiency and certainty over any other objectives in such reviews. In February 2025, CEQ sent an interim final rule to the White House Office of Management and Budget that would immediately withdraw the NEPA implementing regulations. In January 2026, CEQ formally repealed its NEPA implementing regulations. However, the repeal has left the July 2020, Phase I, and Phase II rules in place. This action may be subject to litigation. Congress is also considering legislation designed to streamline NEPA through the Standardizing Permitting and Expediting Economic Development Act ("SPEED Act"). The SPEED Act aims to redefine what qualifies as a "major Federal action" and impose stricter deadlines for NEPA review. Although the SPEED Act has passed the House of Representatives, final passage and implementation remains uncertain. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our operations.

Endangered Species Act and Migratory Bird Treaty Act

The federal ESA was established to protect endangered and threatened species and their habitat. If a species is listed as threatened or endangered pursuant to the ESA, restrictions may be imposed on activities adversely affecting that species or its habitat. The U.S. Fish and Wildlife Service ("FWS") must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. However, the Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental taking under certain prescribed conditions. The future of this rulemaking is uncertain. In April 2024, the U.S. FWS issued three final rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. However, in April 2025, the U.S. Department of Interior issued a memo, M-37085, to repeal M-37065, which had previously declared that the MBTA prohibited both the intentional and incidental "take" of migratory birds. The memo restored M-37050, clarifying that only the intentional "take" of migratory birds is prohibited. Additionally, in April 2025, the FWS and National Marine Fisheries Service proposed to redefine "harm" to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. Additionally, in November 2025, the Trump Administration proposed several rules that would significantly alter ESA protections for plants and animals. One proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. Additionally, a third proposed rule would reinstate the framework for evaluating the benefits and cost of designating a critical habitat by considering factors like economic impact, impact on national security, and other relevant impacts. The FWS is expected to issue final rules in 2026. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on our assets. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress, and the development of regulations continues in the U.S. Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- transportation of materials and equipment to and from our well sites and facilities;
- transportation and disposal of produced fluids and natural gas; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Sale and Transportation of Gas and Oil

The Federal Energy Regulatory Commission ("FERC") has jurisdiction terms and conditions of service under which companies provide interstate transportation of gas, oil and other liquids by pipeline. The FERC does not regulate the sale of oil or petroleum products or the construction of oil or other liquids pipelines, but does regulate the rates and terms and conditions of service on oil and liquids pipelines.

The Beta properties include the San Pedro Bay Pipeline Company, which owns and operates an offshore crude oil pipeline. This pipeline is subject to regulation by the FERC under the Interstate Commerce Act and the Energy Policy Act of 1992. Tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, must be just and reasonable and not unduly discriminatory. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly. The FERC has established a formulaic methodology for oil and liquids pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. During the last review period, FERC set the index level in December 2020. Both pipelines and pipeline customers sought rehearing of the index level, and in January 2022, FERC issued a rehearing order setting a lower index price, effective July 1, 2021, of the producer price index for finished goods minus 0.21%. Pipelines challenged this decision and on July 26, 2024, the D.C. Circuit vacated the rehearing order. Subsequently, on September 17, 2024, FERC issued an order reinstating the index price of producer price index for finished goods plus 0.78%. Then, on October 17, 2024, FERC issued a supplemental notice of proposed rulemaking proposing to reduce the index price back to the producer price index for finished goods minus 0.21%; that proposed rule was withdrawn by FERC on November 20, 2025. On November 20, 2025, FERC issued a Notice of Proposed Rulemaking proposing to set the producer price index for finished goods at minus 1.42% as the index level for the five-year period commencing July 1, 2026. This proposed rule is now pending. The San Pedro Bay Pipeline Company uses the indexing methodology to change its rates.

Although the FERC does not have jurisdiction over the production of gas, the FERC exercises regulatory authority over wholesale sales of gas in interstate commerce through the issuance of blanket marketing certificates that authorize the wholesale sale of gas at market rates and the imposition of a code of conduct on blanket marketing certificate holders that regulate certain affiliate interactions. The FERC also has oversight of the performance of wholesale natural gas markets, including the authority to facilitate price transparency and to prevent market manipulation. In furtherance of this authority, the FERC imposed an annual reporting requirement on all industry participants, including otherwise non-jurisdictional entities, engaged in wholesale physical natural gas sales and purchases in excess of a minimum level. These agency actions have been intended to foster increased competition within all phases of the gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. Also, as discussed above, during 2025, we completed several divestiture transactions and as of the date of this Annual Report, and we are no longer engaged in the production and sale of natural gas.

The FERC and other federal agencies, the U.S. Congress or state legislative bodies and regulatory agencies may consider additional proposals or proceedings that might affect the gas or oil industries. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any such proposal will affect us any differently than it would affect other gas or oil producers with which we compete.

The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. BOEM/BSEE has established formal and informal complaint procedures for shippers that believe they have been denied open and non-discriminatory access to transportation on the OCS.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates the safety of all pipeline transportation in or affecting interstate or foreign commerce, including pipeline facilities on the OCS. The San Pedro Bay pipeline is subject to regulation by the PHMSA. PHMSA regularly updates its pipeline safety rules and recommendations. For example, on March 25, 2025, PHMSA published an advisory bulletin that stated PHMSA's intent to encourage all regulated pipeline owners and operators to voluntarily adopt new safety management systems. PHMSA updates the maximum administrative civil penalties each year to account for inflation, and as of December 2025, the penalty limits are up to $272,926 per violation per day and up to $2,729,245 for a related series of violations. PHMSA has also issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

Anti-Market Manipulation Laws and Regulations

The FERC, with respect to the purchase or sale of natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction, and the Federal Trade Commission (the "FTC") with respect to petroleum and petroleum products, operating under various statutes, have each adopted anti-market manipulation regulations, which prohibit, among other things, fraud and price manipulation in the respective markets. These agencies hold substantial enforcement authority, including the ability to assess substantial civil penalties, to order repayment or disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Derivatives Regulation

Comprehensive financial reform legislation was signed into law by former President Obama on July 21, 2010 (the "Dodd-Frank Act"). This legislation called for the Commodities Futures Trading Commission (the "CFTC") to regulate certain markets for derivative products, including over-the-counter derivatives. The CFTC has issued several new relevant regulations and rulemakings to implement the Dodd-Frank Act, the mandate to cause significant portions of derivatives markets to clear through clearinghouses, along with other mandated changes. While some of these rules have been finalized, some have not. As a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The CFTC's final rules were challenged in court by two industry associations and were vacated and remanded by a federal district court. Subsequently, the CFTC proposed new rules in November 2013 and December 2016. In January 2020, the CFTC withdrew the 2013 and 2016 proposals. In January 2021 the CFTC issued a final rule on the matter, effective March 15, 2021. The final rule includes limits on positions in (1) certain "Core Referenced Futures Contracts," including contracts for several energy commodities; (2) futures and options on futures that are directly or indirectly linked to the price of a Core Referenced Futures Contract, or to the same commodity for delivery at the same location as specified in that Core Referenced Futures Contract; and (3) economically equivalent swaps. The final rule also includes exemptions from position limits for bona fide hedging activities.

The Dodd-Frank Act and new, related regulations may prompt counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may become less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations. Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under (i) the Commodity Exchange Act (the "CEA"), as amended by the Dodd-Frank Act, and regulations promulgated thereunder by the CFTC, and (ii) the Energy Independence and Security Act of 2007 (the "EISA") and regulations promulgated thereunder by the FTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract for sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC's rules and regulations. It also prohibits knowingly delivering or causing to be delivered false, misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity. The FTC's Petroleum Market Manipulation Rule, issued pursuant to EISA, prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. Under both the CEA and the EISA, fines for violations can be up to $1,000,000 per day per violation (subject to adjustment for inflation) and certain knowing or willful violations may also lead to a felony conviction.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, federal agencies and the courts. The Company cannot predict the ultimate impact these proposals may have on its crude oil operations, but the Company does not expect any such action to affect the Company differently than it will affect other gas or oil producers with which we compete.

State Regulation

Various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Human Capital

Overview

On December 31, 2025, the Company had 184 employees, none of whom were represented by labor unions or covered by any collective bargaining agreement. We strive to create a high-performing culture and positive work environment that allows us to attract and retain a group of talented individuals who can foster the Company's success. To attract and retain top talent, our human resources programs are designed to reward and incentivize our employees through competitive compensation practices, our commitment to employee health and safety, training and talent development and our commitment to inclusion.

Safety

Safety is our highest priority, and we are dedicated to the well-being of our employees, contractors, business partners, stakeholders and the environment. We promote safety with a robust health and safety program, which includes employee orientation and training, contractor management, risk assessment, hazard identification and mitigation, audits, incident reporting and investigation, and corrective and preventative action development.

In addition, we employ environmental, health and safety personnel at each of our asset locations, who provide in-person safety training and regular safety meetings. We also utilize learning management software to provide safety training on a variety of topics, and we contract with third-party technical experts to facilitate training on specialized topics that are unique to each of our areas of operation.

It is our policy to provide our employees with a safe and healthy workplace and to follow procedures aimed at safeguarding employees. We believe accident prevention and efficiency in production run hand-in-hand. Our internal Stop Work Authority empowers employees to pause operations so that an observed potential hazard can be eliminated or mitigated.

We are committed to maintaining a safe and healthy work environment by complying with state and federal regulations concerning the health and safety of our employees. Our employees are expected to demonstrate a cooperative spirit by working together to help us in this effort. As such, every employee is directly responsible for the proper care and use of Amplify property and equipment placed in their charge, either temporarily or on a regular basis.

Compensation

We operate in a highly competitive environment and have designed our compensation program to attract, retain and motivate talented and experienced individuals. Our compensation philosophy is designed to align the interests of our workforce with those of our stakeholders and to reward them for achieving the Company's business and strategic objectives and driving shareholder value. We consider competitive market compensation paid by our peers and other companies comparable to us in size, geographic location and operations in order to ensure our compensation remains competitive and fulfills our goal of recruiting and retaining talented employees.

Training and Development

We are committed to the training and development of our employees. Employees are regularly provided training opportunities to develop skills in leadership, safety, and technical acumen, which bolsters our efforts in conducting business in a safe manner and with high ethical standards. Further, we believe that supporting our employees in achieving their career and development goals is a key element of our approach to attracting and retaining top talent. We encourage our employees to advance their knowledge and skills and to network with other professionals in order to pursue career advancement and potential future opportunities with the Company. Our employees are able to attend training seminars and off-site workshops or to join professional associations that will enable them to remain up to date on the latest changes and best practices in their respective fields.

Inclusion

We are committed to supporting an inclusive workplace and career development opportunities to attract and retain talented employees. As of December 31, 2025, approximately 56% of our total workforce self-identified as a racial or ethnic minority and approximately 18% self-identified as female. As of the same date, approximately 57% of the employees located in our corporate headquarters self-identified as a racial or ethnic minority and approximately 67% self-identified as female. It is our policy to prohibit discrimination and harassment of any type and afford equal employment opportunities to employees and applicants without regard to race, color, religion, sex, national origin, age, disability, genetic information, veteran status, or any other basis protected by federal, state or local law. Further, it is our policy to forbid retaliation against any individual who reports, claims, or makes a charge of discrimination or harassment, fraud, unethical conduct, or a violation of our Company policies. To sustain and promote an inclusive culture, we maintain a robust compliance program rooted in our Code of Business Conduct and Ethics and other Company policies, which provide policies and guidance on non-discrimination, anti-harassment, and equal employment opportunities. We require all employees to complete periodic training sessions on various aspects of our corporate policies through an annual acknowledgment and certification process.

Health and Wellness

We support our employees and their families by offering a robust package of health and welfare benefits, medical, dental, and vision insurance plans for employees and their families, life insurance and long-term disability plans, paid time off for holidays, vacation, sick leave, and other personal leave, and health and dependent care savings accounts. We also provide our employees with a 401(k) plan that includes a competitive company match, and employees have access to a variety of resources and services to help them plan for retirement.

In addition to these programs, we have several other programs designed to further promote the health and wellness of our employees, including, among others, an employee assistance program that offers counseling and referral services for a broad range of personal and family situations.

The success of our business is fundamentally connected to the safety and well-being of our employees. Our focus remains on providing a safe office environment for our employees while continuing to allow for remote work, hybrid work and flexible work schedules where feasible. With the support of the varying work arrangements and a geographically dispersed workforce, we continue to develop ways to best support our people.

Offices

Our principal executive office is located at 500 Dallas Street, Suite 1700, Houston, Texas 77002. Our main telephone number is (832) 219-9001.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website at www.amplifyenergy.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. Our website also includes our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating & governance committee. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

The SEC maintains a website that contains reports, proxy and information statements, and other information regarding the Company at www.sec.gov.

ITEM 1A. RISK FACTORS

Our business and operations are subject to many risks. The risks described below, in addition to the risks described in "Item 1. Business" of this Annual Report, may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. You should carefully consider the following risk factors together with all of the other information included in this Annual Report, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this Annual Report could have a material adverse effect on our business, financial position, results of operations and cash flows and the trading price of our securities could decline, and you could lose all or part of your investment.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of, oil, natural gas and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our assets depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for developing, producing and transporting reserves;
- the price and quantity of foreign imports, including volatility as a result of tariffs and other trade-related disputes;
- political and economic conditions in oil producing countries, including conflicts in or among the Middle East, Africa, South America, Russia and Israel;
- the ability of members of the Organization of Petroleum Exporting Countries ("OPEC") to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with a pandemic, epidemic or outbreak of an infectious disease;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;

- the impact of energy conservation efforts;
- the continued threat of terrorism and the impact of military and other action, including the Russian invasion of Ukraine and ongoing conflicts or entanglements in the Middle East and South America, and the potential destabilizing effect such conflicts may pose for those regions and/or the global oil and natural gas markets;
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2025, the NYMEX-WTI oil future price ranged from a high of $122.11 per Bbl to a low of $47.62 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $9.68 per MMBtu to a low of $1.58 per MMBtu. For the year ended December 31, 2025, the WTI posted prices ranged from a high of $80.04 per Bbl on January 5, 2025 to a low of $55.27 per Bbl on December 16, 2025 and NYMEX-Henry Hub natural gas market price ranged from a high of $5.29 per MMBtu on December 5, 2025 to a low of $2.70 per MMBtu on August 22, 2025. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which has different uses and different pricing characteristics, have sustained depressed realized prices during this period and are generally correlated with the price of oil. An extended decline in commodity prices could materially and adversely affect our business, results of operations and financial condition, could render many of our development and production projects uneconomical and could result in a downward adjustment of our reserve estimates.

The Company recognized an impairment expense of $42.5 million for the year ended December 31, 2025. The Company recognized an impairment charge due to the carrying value of the assets exceeding the fair market value of the assets sales price. No impairment expense was recognized for the year ended December 31, 2024. An extended decline in commodity prices may cause us to write down, as a non-cash charge to earnings, the carrying value of our oil properties for impairment. We may in the future incur impairment charges that could have a material adverse effect on our results of operations in the period taken.

We are dependent upon a small number of significant customers for the majority of our production sales. The loss of those customers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition and results of operations.

We had two customers that each accounted for 10% or more of total reported revenues for the year ended December 31, 2025. The loss of these customers or any significant customer, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. Also, if any significant customer reduces the volume it purchases from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our production, or we could be required to shut in all or a portion of our production, any of which could cause our revenues and cash flows to decline and have a material adverse effect on our results of operations. For instance, in October 2024, Phillips 66 announced its plan to cease operations at its Los Angeles area refinery in the fourth quarter of 2025. Given that this refinery had historically made up all of our Beta sales, we had to seek out new customers in the area to replace the volume previously purchased by Phillips 66. Further, these risks may be greater in the future following the completion of several divestiture transactions in 2025, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisiana assets in December 2025, and our Oklahoma assets in December 2025, as sales to these significant customers may constitute an even greater percentage of our total reported revenues in future periods. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production. See "Item 1. Business — Operations — Marketing and Major Customers."

Our business could be adversely affected by a decline in general economic conditions or a weakening of the broader energy industry, and inflation may adversely affect our financial position and operating results.

A prolonged economic slowdown or recession, adverse events relating to the energy industry, volatility due to tariffs or other trade-related disputes, or regional, national, or global economic conditions and factors, particularly a slowdown in the exploration and production industry, could negatively impact our operations and therefore adversely affect our results. The risks associated with our business are more acute during periods of economic slowdown or recession because such periods may be accompanied by decreased demand for oil and natural gas and decreased prices for oil and natural gas.

Inflationary factors, such as increases in the labor costs, material costs, and overhead costs, may also adversely affect our financial position and operating results. Inflation has also resulted in higher interest rates in the United States, which could increase our cost of debt borrowing in the future.

Our properties are concentrated in a limited number of geographic locations and adverse developments, including potential difficulties in the marketing of oil, in such operating areas could adversely affect our business, financial condition, results of operations and cash flows.

As of December 31, 2025, following the completion of our divestitures, our properties are currently located in the Rockies and federal waters offshore Southern California. As a result, our business, financial condition, results of operations and cash flows may be disproportionately affected by adverse developments in these geographic areas, including regional events such as severe weather conditions, natural disasters, regulatory changes, infrastructure changes or local economic downturns. Additionally, increased competition, changes in the availability of services, equipment or the ability to attract and retain field personnel in these concentrated regions, could result in higher costs or operational delays. Any disruption, limitation or curtailment of operations in these areas, whether due to physical, regulatory or market-driven factors, or any potential difficulties in the marketing of our oil from such properties, could materially and adversely affect our overall performance.

The inability of our significant customers, vendors or other counterparties to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to the concentration of our oil and natural gas receivables. The inability or failure of our significant customers, or any purchasers of our production, to meet their payment obligations to us or their insolvency or liquidation could have a material adverse effect on our results of operations. To the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge to earnings of that period for the probable loss and could suffer a material reduction in our liquidity and cash flows.

Further, we are exposed to risks of loss in the event of nonperformance by our vendors and other counterparties. Some of our vendors and other counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors and other counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors' and other counterparties' liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors and/or counterparties could adversely affect our business, financial condition, results of operations and cash flows.

We are subject to, and in the future may be subject to additional complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations administered by governmental authorities vested with broad authority relating to the exploration for and the development, production and transportation of oil and natural gas. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our oil and natural gas development and production operations are also subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance measures or corrective actions. Further, the Incident (as defined below) or any similar future incidents may result in more stringent permitting obligations and regulation of our properties and other oil and gas activities, including at Beta and elsewhere, particularly relating to environmental, health and safety protection controls, oversight of oil and gas operations and required financial assurance. Regulatory or legislative action may impact the industry as a whole and could be directed specifically towards operators similarly situated to us, which could negatively impact our business. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

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

Further, the Mineral Leasing Act of 1920, as amended (the "Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. We qualify as an entity formed under the laws of the United States or of any U.S. state or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. It is possible that our stockholders may be citizens of foreign countries who do not own their stock in a U.S. corporation, or that even if such stock are held through a U.S. corporation, their country of citizenship may be determined to be non-reciprocal countries under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the more significant laws and regulations that affect us.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could significantly reduce our cash flow and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as NYMEX or ICE, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our Beta oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at certain benchmark prices. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it may sell at a discount to those prices. These discounts, if significant, could reduce our cash flows and adversely affect our results of operations and financial condition.

The production from our Bairoil properties could be adversely affected by the cessation or interruption of the supply of CO_2 to those properties.

We inject water and CO_2 into formations on substantially all of the Bairoil properties to increase production of oil and natural gas. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If we are unable to produce oil and gas by injecting CO_2 in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 to enhance production is subject to our ability to obtain sufficient quantities of CO_2. If, under our CO_2 supply contracts, the supplier is unable to deliver its contractually required quantities of CO_2 to us, or if our ability to access adequate supplies is impeded, then we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes will be negatively impacted.

Certain carbon dioxide purchase agreements are priced based on our counterparty's ability to claim federal income tax credits which depend, in part, on our compliance with the requirements of such tax credits. If we are unable to comply with those requirements, or if Congress enacts new legislation, we will face increased payment obligations for carbon dioxide, which will negatively impact our economics.

Internal Revenue Code Section 45Q, and its accompanying Treasury Regulations provide, as relevant to our operations, a federal income tax credit for capturing of carbon oxides ("CO2") from industrial processes that are used for enhanced oil recovery (the "Section 45Q Credit"). We purchase CO2 from counterparties that are eligible for the Section 45Q Credit provided we use the CO2 for enhanced oil recovery ("EOR") in compliance with the Section 45Q Credit rules. We have negotiated certain CO2 purchase agreements to allow us to share in the value of the Section 45Q Credit in the form of reduced CO2 pricing.

The availability of the Section 45Q Credit, and associated reductions in our CO2 payments, require ongoing compliance by both us and our supplier with an evolving legal and regulatory regime. If Congress revises the Section 45Q Credit, including with retroactive effect, we, or our CO2 supplier may be unable to realize the Section 45Q Credit benefits. Even if Congress does not revise the Section 45Q Credit, it is possible that we are unable to comply with the existing or modified regulatory regimes. In both instances, we will incur higher CO2 costs, which will negatively impact our economics.

Additionally, if we are unable to utilize CO2 for EOR purposes consistent with the Section 45Q Credit requirements, or the CO2 that we purchase leaks from our EOR wells, we will have an indemnity obligation to our CO2 supplier, which will eliminate the savings to which we would otherwise be entitled.

While we have negotiated our CO2 purchase contracts consistent with the Section 45Q Credit requirements and are undertaking our EOR activities in a manner that we believe enables our CO2 supplier to be eligible for the Section 45Q Credit (and corresponding reduced CO2 pricing), there can be no assurances that the IRS will agree with our positions. Any successful challenge by the IRS would reduce or eliminate the Section 45Q Credit and associated cost savings from our reduced CO2 pricing.

The failure to replace our proved oil reserves could adversely affect our business, financial condition, results of operations, production and cash flows.

Producing oil reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil reserves and production and therefore, our cash flows, are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production at economically acceptable terms, which would materially and adversely affect our business, financial condition and results of operations.

If we reduce our capital spending in an effort to conserve cash, this would likely result in production being lower than anticipated, and could result in reduced revenues, cash flows from operations and income. Further, if our revenues decrease, as a result of lower oil prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations.

Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of operating and development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds.

Actual future production, oil prices, revenues, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved reserves shown in this report, or standardized measure, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the FASB, we base the estimated discounted future net cash flows from our proved reserves on the trailing 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then-current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements, which is required by the SEC and FASB, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition, results of operations and cash flows.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of our development and production activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, our development and production operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- high costs, shortages or delivery delays of equipment, labor, electrical power or other services;
- unusual or unexpected geological formations;

- composition of sour natural gas, including sulfur, carbon dioxide and other diluent content;
- unexpected operational events and conditions;
- failure of down hole equipment and tubulars;
- loss of wellbore mechanical integrity;
- failure, unavailability or shortage of capacity of gathering and transportation pipelines, or other transportation facilities;
- human errors, facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour natural gas;
- title problems;
- loss of drilling fluid circulation;
- hydrocarbon or oilfield chemical spills;
- fires, blowouts, surface craterings and explosions;
- surface spills or underground migration due to uncontrollable flows of oil, natural gas, formation water or well fluids;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements; and
- adverse weather conditions and natural disasters.

Additionally, our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, all of which could cause substantial financial losses. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of potential damages resulting from these risks.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations are delayed or canceled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected. If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition, results of operations and cash flows.

Expenses not covered by our insurance could have a material adverse effect on our financial position and results of operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, insurance against all operational risk is not available to us. These insurance policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A liability, claim or other loss not fully covered by insurance could have a material adverse effect on our business, financial position, results of operations and cash flows.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil production.

The marketability of our oil production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. For example, our ability to produce and sell oil from the Beta properties will depend on the availability of the pipeline infrastructure between platforms as well as the San Pedro Bay Pipeline for delivery of that oil to shore, and any unavailability of that pipeline infrastructure or pipeline could cause us to shut in all or a portion of the production from the Beta properties for the length of such unavailability. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering systems or transportation or processing facility capacity could reduce our ability to market our oil production and harm our business, financial condition, results of operations and cash flows.

Development and production of oil and natural gas in offshore waters have inherent and historically higher risk than similar activities onshore.

Our offshore operations are subject to a variety of operating risks specific to the marine environment, such as a dependence on a limited number of electrical transmission lines, as well as capsizing, collisions and damage or loss from adverse weather conditions. Offshore activities are subject to more extensive governmental regulation than our other oil and natural gas activities. We are vulnerable to the risks associated with operating in the Pacific Outer Continental Shelf, including risks relating to:

- impacts of climate change and natural disasters such as earthquakes, tidal waves, mudslides, fires and floods;
- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- third-party marine vessels, such as the anchor dragging incident at Beta in 2021;
- remediation and other costs resulting from oil spills, releases of hazardous materials and other environmental and natural resource damages; and
- failure of equipment or facilities.

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because significant portions of our offshore operations are conducted in environmentally sensitive areas, including areas with significant residential populations and public and commercial infrastructure. An accidental oil spill or release on or related to offshore properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of remediating a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. If an oil discharge or substantial threat of discharge were to occur, we may be subject to regulatory scrutiny and liable for costs and damages, which costs and damages could be material to our business, financial condition or results of operations and could subject us to criminal and civil penalties. Finally, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts covering at least 25%- 75%, depending on availability under the Revolving Credit Facility, of our estimated production from proved developed producing reserves over a one-year period at any given point in time. These commodity derivative contracts include natural gas, oil and NGL financial swaps, put options, costless collars, and three-way collars. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations, at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices received for our future production. Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and NGL prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

Many of our properties are in areas that may have been partially depleted or drained.

Many of our properties are in areas that may have already been partially depleted or drained. The owners of leasehold interests lying contiguous or adjacent to or adjoining any of our properties could take actions, such as drilling additional wells that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further exploit and develop our reserves.

Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. We cannot predict in advance of drilling, testing and analysis of data whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. Our ability to drill, recomplete and develop locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure and lease expirations. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition, results of operations and cash flows.

Loss of our key executive officers or other key personnel, or an inability to attract and retain such officers and personnel, could negatively affect our business.

Our future success depends on the skills, experience and efforts of our key executive officers. The sudden loss of any of these executives' services or our failure to appropriately plan for any expected key executive succession could materially and adversely affect our business and prospects, as we may not be able to find suitable individuals to replace them on a timely basis, if at all. Additionally, we also depend on our ability to attract and retain qualified personnel to operate and expand our business. If we fail to attract or retain talented new employees, our business and results of operations could be negatively affected.

Part of our strategy may involve using horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations may involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we may face while drilling horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we may face while completing wells include, but are not limited to, the following:

- the ability to run tools the entire length of the wellbore during completion operations; and

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

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

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies and we could incur losses as a result of such expenditures. As a result, future drilling activities may not be successful or economical, which could have a material adverse impact on our financial condition, results of operations and cash flows.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and will likely continue to limit our ability to book additional PUDs, especially in a time of depressed commodity prices. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

The unavailability or high cost of equipment, supplies and crews could delay our operations, increase our costs and delay forecasted revenue.

Our industry is cyclical, and historically there have been periodic shortages of equipment, supplies and crew. Sustained declines in oil and natural gas prices may reduce the number of service providers for equipment, supplies and crews, contributing to or resulting in shortages. Alternatively, during periods of higher oil and natural gas prices, the demand for equipment, supplies and crews is increased and can lead to shortages of, and increasing costs for, development equipment, supplies, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict the Company's ability to drill the wells and conduct the operations that it currently has planned relating to the fields where our properties are located. In addition, some of our operations require supply materials for production, such as CO_2, which could become subject to shortages and increased costs. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and impact our development plan, which would thus affect our financial conduction, results of operations and our cash flows.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry-on refining operations and market petroleum and other products on a regional, national or worldwide basis and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition, results of operations and cash flows.

We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.

Under our Revolving Credit Facility, we are required to (i) maintain, as of the date of determination, a maximum total debt to EBITDAX ratio of 3.00 to 1.00, commencing with the fiscal quarter ending March 31, 2026, (ii) maintain a current ratio of not less than 1.00 to 1.00, and (iii) hedge at least 25%–75%, depending on availability under the Revolving Credit Facility, of our estimated production from total proved developed producing reserves. If we were to violate any of the covenants under our Revolving Credit Facility and were unable to obtain a waiver or amendment, it would be considered a default after the expiration of any applicable grace period. If we were in default under our Revolving Credit Facility, then the lenders may exercise certain remedies including, among others, declaring all borrowings outstanding thereunder, if any, immediately due and payable. This could adversely affect our operations and our ability to satisfy our obligations as they come due, because we might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Revolving Credit Facility are secured by mortgages on not less than 90% of the PV-9 value of our oil and gas properties together with all or substantially all material midstream assets necessary to operate our proved, developed and producing oil and gas properties, and if we are unable to repay our indebtedness under our Revolving Credit Facility, the lenders could seek to foreclose on our assets.

Restrictive covenants in our Revolving Credit Facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Restrictive covenants in our Revolving Credit Facility impose significant operating and financial restrictions on us and our subsidiaries. These restrictions limit our ability to, among other things:

- incur additional liens;
- incur additional indebtedness;
- merge, consolidate or sell our assets;
- pay dividends or make other distributions or repurchase or redeem our stock;
- make certain investments; and
- enter into transactions with our affiliates.

Our Revolving Credit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under our Revolving Credit Facility. If a default occurs and remains uncured or unwaived, the administrative agent or majority lenders under our Revolving Credit Facility may elect to declare all borrowings outstanding thereunder, if any, together with accrued interest and other fees, to be immediately due and payable. The administrative agent or majority lenders under our Revolving Credit Facility would also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay our indebtedness when due or declared due, the administrative agent will also have the right to proceed against the collateral pledged to it to secure the indebtedness under our Revolving Credit Facility. If such indebtedness were to be accelerated, our assets may not be sufficient to repay in full our secured indebtedness.

We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants in our Revolving Credit Facility. The terms and conditions of our Revolving Credit Facility affect us in several ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increasing our vulnerability to economic downturns and adverse developments in our business;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- placing restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limiting management's discretion in operating our business.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

Borrowings under our Revolving Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Our lenders periodically redetermine the amount we may borrow under our Revolving Credit Facility, which may materially impact our operations.

Our Revolving Credit Facility allows us to borrow in an amount up to the borrowing base, which is primarily based on the estimated value of our oil properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. The borrowing base is subject to redetermination on at least a semi-annual basis primarily based on an engineering report with respect to our estimated oil and NGL reserves, which takes into account the prevailing natural gas, oil and NGL prices at such time, as adjusted for the impact of our commodity derivative contracts. Accordingly, declining commodity prices may have an impact on the amount we can borrow, which could affect our cash flows and ability to execute our business plans. Any further reduction in the borrowing base may affect our business and financing activities, limit our flexibility and management's discretion in operating our business, and increase the risk that we may default on our debt obligations. In addition, as hedges roll off, the borrowing base is subject to further reduction. Our Revolving Credit Facility requires us to repay any deficiency over a certain period or pledge additional oil and gas properties to eliminate such deficiency within 30 days of notice. If our outstanding borrowings exceed the borrowing base and we are unable to repay the deficiency or pledge additional oil and gas properties to eliminate such deficiency, our failure to repay any of the installments due related to the borrowing base deficiency would constitute an event of default under the Revolving Credit Facility and as such, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, or foreclose against the assets securing the obligations owed under our Revolving Credit Facility.

Our business is subject to climate-related transition risks, including fuel conservation measures, technological advances and increasing public attention to climate change and environmental matters, which could reduce demand for oil and natural gas and have an adverse effect on our business, financial condition and reputation.

Increased attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on responding to climate change, together with fuel conservation measures, alternative fuel requirements, incentives to conserve energy or use alternative energy sources, and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services, increasing consumer demand for alternatives to oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles), societal expectations on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, and technological advances in fuel economy and energy transmission, storage, consumption and generation devices (including advances in wind, solar and hydrogen power, as well as battery technology), could reduce demand for oil and natural gas. Such initiatives or related activism aimed at responding to climate change and reducing air pollution, as well as negative investor sentiment toward our industry and the impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations, cash flows, and ability to access capital.

The oil and natural gas industry, and energy industry more broadly, is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, including technological advances in fuel economy and energy generation devices or other technological advances that could reduce demand for oil and natural gas, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Moreover, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies such as ours may be more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding or higher cost of capital for potential development projects, as well as the restriction, delay or cancellation of infrastructure projects and energy production activities, ultimately impacting our future financial results.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change, may also lead to increased litigation risk and regulatory, legislative, and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance or have caused other redressable injuries under federal and/or state common law. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, various officials and candidates at the federal, state and local levels have made climate-related pledges. More broadly, the enactment of climate change-related policies and initiatives across the market at the corporate level and/or investor community level may in the future result in increases in the Company's compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation). For further discussion regarding the transition risks posed to us by climate change-related regulations, policies and initiatives, see the discussion below in "—Climate change legislation or regulations restricting emissions of "greenhouse gases," or GHGs, could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects."

Increasing scrutiny and changing stakeholder expectations in respect of environmental, social and governance ("ESG") and sustainability practices may have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Companies across all industries are facing increasing scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors and lenders, investment funds and other influential investors and rating agencies, related to their sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on sustainability matters as they continue to evolve, meet sustainability-related goals that we have set, or if we are perceived to have not responded appropriately or quickly enough to growing concern for sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected.

In addition, the Company's continuing efforts to research, establish, accomplish, and accurately report on the implementation of our sustainability strategy, including any specific sustainability objectives, may also create additional operational risks and expenses and expose us to reputational, legal, and other risks. While we create and publish voluntary disclosures regarding sustainability matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many sustainability matters. Further, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to sustainability matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable sustainability ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, many of whom are focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating public company. At the same time, recent political developments could subject the Company to increased risk of criticism or litigation risks from certain "anti-ESG" parties. Such sentiment may focus on the Company's GHG reduction initiatives, which anti-ESG proponents may assert as unlawful, political or polarizing in nature. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder trust and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

Climate change legislation or regulations pertaining to emissions of "greenhouse gases," or GHGs, could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

The EPA has adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the CAA. In addition, the EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Such climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

In August 2022, then-President Biden signed into law the Inflation Reduction Act of 2022. The Inflation Reduction Act includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a WEC on certain oil and gas sources that are already required to report under EPA's Greenhouse Gas Reporting Program. To implement the program, in May 2024, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. The emissions reported under the Greenhouse Gas Reporting Program were set as the basis for any payments under the Methane Emissions Reduction Program. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. In addition, EPA proposed on September 12, 2025 to eliminate or suspend Greenhouse Gas Reporting Program requirements for most industries, with final rules implementing the proposed rollback expected by mid-2026. In November 2024, the EPA finalized a regulation to implement the Inflation Reduction Act's WEC. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. In addition, in March 2025, President Trump signed Congress' Joint Resolution of Disapproval of the WEC, and in May 2025, the EPA issued a final rule to remove the WEC regulations from the Code of Federal Regulations. In July 2025, the One Big Beautiful Bill Act delayed the effective date of the WEC until 2034. Consequently, future implementation and enforcement of these rules remain uncertain at this time. Additionally, many of the states have taken legal measures to reduce emissions of GHGs, including through the planned development of GHG emission inventories and/or regional GHGs cap and trade programs. For example, in October 2023, California enacted legislation that will ultimately require certain companies that do business in California to publicly disclose certain climate-related information, including their Scopes 1, 2 and 3 GHG emissions, with third party assurance of such data, and their climate-related financial risks and related mitigation measures with certain disclosures required in 2026. These laws are subject to ongoing legal challenges and certain requirements are currently enjoined. It is unclear how the litigation process and additional legal developments will impact enforceability of these requirements and the timeline and cost of compliance.

The 2007 case Massachusetts v. EPA held that GHGs are air pollutants covered by the Clean Air Act, and that EPA must determine whether certain GHG emissions may reasonably be anticipated to endanger public health or welfare. In December 2009, EPA issued a final rule stating that current and projected concentrations of carbon dioxide, methane and other GHGs endanger public health and welfare ("2009 Endangerment Finding"). The 2009 Endangerment Finding served as legal support for subsequent EPA Clean Air Act rulemakings that have significantly affected industry operational costs, including New Source Performance Standards and Existing Source Guidelines rules requiring technology investments to detect and reduce methane leaks and emissions from new and existing oil and gas infrastructure. In the 2022 Supreme Court case West Virginia v. EPA, the Court held that EPA lacked clear statutory authority under the Clean Air Act, absent specific and explicit authorization from Congress, to implement an EPA rulemaking that mandated a shift for electricity production from higher greenhouse gas emissions sources to lower emissions sources. In the 2024 Supreme Court case Loper Bright Enters. v. Raimondo, the Court held that courts must independently determine the best reading of a statute, rather than deferring to agency interpretations of ambiguous statutory language. On February 12, 2026, EPA issued a pre-publication copy of a final rule, submitted for publication in the Federal Register, rescinding the 2009 Endangerment Finding on the basis that the 2009 Endangerment Finding exceeded EPA authority, was not supported by specific and explicit authorization from Congress, and did not meet the best reading of the underlying Clean Air Act provision under the West Virginia and Loper Bright holdings. Litigation following the February 2026 final rule publication is expected, and the potential impact of the February 2026 final rule, potential subsequent revisions to existing emission standards, and the outcome of related litigation, including private nuisance litigation, remain uncertain and could affect our operations.

At the international level, in 2015, at COP21 the international community adopted the Paris Agreement, an international treaty aimed at addressing climate change whereby parties agreed to determine national contributions and set GHG emission reduction goals every five years beginning in 2020. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement. The withdrawal became effective in January 2026. In January 2026, President Trump announced the United States will also withdraw from the UN Framework Convention on Climate Change. Despite this, various states and local governments have vowed to continue to enact regulations to achieve the goals of the Paris Agreement, and related initiatives are expected to continue.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions (including those related to carbon pricing schemes) would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce and restrict our ability to execute on our business strategy, reducing our access to financial markets, or create greater potential for governmental investigations or litigation.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. For example, such effects could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, increases in our costs of operation or reductions in the efficiency of our operations, impacts on our personnel, supply chain, or distribution chain, as well as potentially increased costs for or limited availability of insurance coverages in the aftermath of such effects. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. Further, energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes. Increased energy use due to weather changes may require us to invest in additional equipment to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. The effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions.

The listing of a species as either "threatened" or "endangered" under the federal Endangered Species Act could result in increased costs, new operating restrictions, or delays in our operations, which could adversely affect our results of operations and financial condition.

The ESA and analogous state laws regulate activities that could have an adverse effect on threatened and endangered species. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our activities in those areas or during certain seasons, such as breeding and nesting seasons. The listing of species in areas where we operate or, alternatively, entry into certain range-wide conservation planning agreements could result in increased costs to us from species protection measures, time delays or limitations on our activities, which costs, delays or limitations may be significant and could adversely affect our results of operations and financial position. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our and our customers' business or operations.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely for gathering and transportation services could impact the availability of those services. Any potential impact to the availability of gathering and transportation services could impact our ability to market and sell our production, which could have a material adverse effect on our business, financial condition and results of operations. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the laws and regulations that affect the third parties on whom we rely for gathering and transportation services.

Oil and natural gas producers' operations, are substantially dependent on the availability of water and the disposal of waste, including produced water and drilling fluids. Restrictions on the ability to obtain water or dispose of waste may impact our operations.

Water is an essential component of oil and natural gas production during the drilling process. Our inability to locate sufficient amounts of water or to dispose of or recycle water used in our development and production operations could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into "waters of the United States." Permits must be obtained to discharge pollutants to such waters and to conduct construction activities in such waters, which include certain wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater and the disposal and recycling of produced water, drilling fluids, and other wastes, may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted. In addition, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In some jurisdictions, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity or resulted in stricter regulatory requirements relating to the location and operation of underground injection wells. Any additional orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations — Water Discharges and Other Waste Discharges & Spills" and "— Hydraulic Fracturing" for an additional description of the laws and regulations relating to the discharge of water and other wastes and hydraulic fracturing that affect us.

The cost of decommissioning is uncertain.

We are required to maintain reserve funds to provide for the payment of decommissioning costs associated with the Beta properties. The estimates of decommissioning costs are inherently imprecise and subject to change due to changing cost estimates, oil and natural gas prices and other factors. If actual decommissioning costs exceed such estimates, or we are required to provide a significant amount of additional collateral in cash or other security as a result of a revision to such estimates, our financial condition, results of operations and cash flows may be materially adversely affected.

We are required to post cash collateral, and in the future we may be required to post additional collateral, pursuant to our agreements with sureties under our existing or future bonding arrangements, which may have a material adverse effect on our liquidity and our ability to execute our capital expenditure plan, our ARO plan and comply with our existing debt instruments.

Pursuant to the terms of our existing bonding arrangements with various sureties in connection with the decommissioning obligations related to our Beta properties, or under any future bonding arrangements we may enter into, we may be required to post additional collateral at any time, on demand, at the sureties' sole discretion. If additional collateral is required to support surety bond obligations, this collateral would probably be in the form of cash or letters of credit, certificate of deposit or other similar forms of liquid collateral. We cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for future bonds.

We have two escrow funding agreements with certain of our surety providers to fund interest-bearing escrow accounts to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. If we fail to comply with our obligations under such escrow agreements, the surety providers may request additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If we are required to provide additional collateral pursuant to any such request or otherwise, our liquidity position may be negatively impacted, and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures in the current year or future years, may be unable to execute our asset retirement obligation plan or may be unable to comply with our existing debt instruments. If we are unable or unwilling to provide additional collateral, we may have to pursue alternate bonding arrangements with other sureties. See Note 7, "Asset Retirement Obligations" and Note 17, "Commitments and Contingencies — Supplemental Bond for Decommissioning Liabilities Trust Agreement" of the Notes to Consolidated Financial Statements included under Part II, "Item 8. Financial Statements and Supplementary Data," in this Annual Report for additional information.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

From time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Such proposed legislative changes have included, but have not been limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, or IDCs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any of the foregoing or similar proposals will be considered and enacted as part of future tax reform legislation and if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development and any such change could have an adverse effect on the Company's financial position, results of operations and cash flows.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our financial condition and results of operations.

Any failure to maintain effective internal control over financial reporting could impair the reliability of our financial statements, which in turn could harm our business, impair investor confidence in the accuracy and completeness of our financial reports and our access to the capital markets and cause the price of our Common Stock to decline and subject us to regulatory penalties.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"), and for evaluating and reporting on that system of internal control. Our ICFR is a process designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of the Company, as appropriate, to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. As a public company, we are required to certify our compliance with Section 404 of the Sarbanes-Oxley Act, which requires us to furnish annually a report by management on the effectiveness of our ICFR.

As part of our ongoing monitoring and assessment of internal controls for the year ended December 31, 2025, we discovered a material weakness in our internal controls related to the lack of the appropriate control processes and activities to sufficiently mitigate for changes in personnel with the necessary technical and accounting knowledge, experience, and training that requires remediation. The Company assessed the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this assessment, because of the effect of the material weakness, the Company's management concluded that the Company's internal control over financial reporting was not effective as of December 31, 2025, based on the criteria set forth under the COSO Framework.

While the material weakness did not result in any identified misstatements to the financial statements and there were no changes to previously released financial results, effective internal controls and disclosure controls and procedures are necessary for us to provide reliable financial reports and disclosures to shareholders, to prevent fraud and to operate successfully as a public company. For additional information, see "Item 9A. Controls and Procedures." While we intend to remediate the material weakness in 2026, there can be no assurance that we will be able to successfully complete the remediation within the contemplated timeline.

We will continue to periodically test and update, as necessary, our internal control systems, including our financial reporting controls. However, our actions may not be sufficient to result in an effective internal control environment, and if we fail to implement and maintain effective ICFR, our ability to accurately and timely report our financial results could be impaired, which could result in late filings of our periodic reports under the Exchange Act, restatements of our consolidated financial statements, suspension or delisting of our Common Stock from the NYSE. Such events could harm our business, cause investors to lose confidence in the accuracy and completeness of our reported financial information, cause the trading price of our shares of Common Stock to decline, limit our access to the capital markets or other financing sources and subject us to investigations, enforcement actions or regulatory penalties.

The operation of our business leverages IT infrastructure across our offices and facilities, and our business systems may (i) be susceptible to errors, shutdowns, sufficiency issues, or technical difficulties, (ii) experience security incidents impacting the integrity of sensitive data processed thereby, and (iii) be subject to evolving and potentially burdensome legal compliance requirements, including requirements around data privacy and security and the use of artificial intelligence technologies.

We may be subject to data protection, privacy, cybersecurity and/or other information security laws and regulations in the jurisdictions in which they do business (collectively, "Privacy Laws"). Compliance with the applicable Privacy Laws may require adhering to stringent legal and operational requirements, which could increase compliance costs for us and require the dedication of additional time and resources to compliance for such entities which may increase over time. A failure to comply with such Privacy Laws could result in fines, sanctions or other penalties, which could materially and adversely affect the results of operations and overall business, as well as our reputation. Our operations will be impacted by a growing movement to adopt comprehensive privacy and data protection laws, where such laws generally focus on privacy as an individual right.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Our cybersecurity strategy is risk-based and is designed to reduce the likelihood and impact of cyber threats through prevention, detection, analysis, response, and resiliency. Our risk management processes include technical controls, policy enforcement mechanisms, continuous monitoring, contractual arrangements, use of third-party tools and services, and management oversight to assess, identify, and manage risks from cybersecurity threats. We implement controls to protect Company information (including the information of our customers and other third parties), our information systems, our business operations, and our products and services. However, our financial, accounting, data processing, portfolio monitoring, backup or other operating systems and facilities may fail to operate properly or become disabled or damaged as a result of a number of factors including events that are wholly or partially beyond our control.

We have adopted security control principles primarily based on the National Institute of Standards and Technology Cybersecurity Framework (NIST CSF) and, where applicable to our operational technology (OT) environment, ISA/IEC 62443. We also leverage industry and government associations, third party benchmarking, internal and external Company audit results, threat intelligence feeds, and similar resources to inform our cybersecurity processes and resource allocation. We consume threat intelligence from multiple vendors including our cyber insurance partners and integrate those insights into our monitoring, detection, and response workflows.

Our information security program includes physical, administrative, and technical safeguards, and plans and procedures designed to help us timely and effectively respond to cybersecurity threats or incidents, including those involving third-party service providers that have access to our systems or data or that support critical business operations. Despite our implementation of a variety of security measures, our computer systems, networks, and data, like those of other companies, could be subject to cybersecurity threats or incidents. Cybersecurity threats or incidents are considered to be any adverse event that threatens the confidentiality, integrity or availability of the information resources of us or our portfolio companies. The result of these cybersecurity threats or incidents may include disrupted operations, including the ability to make distributions, misstated or unreliable financial data, failure to maintain the security, confidentiality or privacy of sensitive data, including personal information relating to investors (and the beneficial owners of investors), liability for stolen assets or information, regulatory penalties, increased cyber security protection and insurance costs, litigation and damage to business relationships, reputational damage, and increased costs associated with mitigation of damages and remediation. Through our cybersecurity risk management process overseen by the Amplify Information Technology Steering Committee (the "Steering Committee") we continuously monitor vulnerabilities and potential attack vectors and evaluate the potential operational and financial effects of cyber threats and of the countermeasures we implement to defend against them. This process is integrated into the Company's overall Risk Management Program, and our Cyber Incident Response planning is integrated into our Business Continuity Program. In addition, we engage independent third-party consultants on a routine basis to assess, enhance, implement, and monitor our cybersecurity risk management program and to support incident response.

We conduct regular Company-wide awareness activities, including monthly cybersecurity training and weekly phishing simulations, and we run tabletop exercises and targeted, role-based modules for higher risk users. The results of these activities, along with key risk indicators and program metrics, are reviewed by management and shared with oversight bodies.

Our Steering Committee was established to further strengthen our cybersecurity risk management activities across the Company, including the prevention, detection, mitigation and remediation of cybersecurity incidents. The Steering Committee has primary management oversight responsibility for assessing and managing risks from cybersecurity threats and is responsible for developing and coordinating enterprise cybersecurity policies and strategies and for providing guidance to key management and oversight bodies. Our Vice President of Information Technology, who has nearly two decades of information technology and cybersecurity risk management experience, serves as the chair of the Steering Committee. The Steering Committee includes senior executives and managers, with significant risk management expertise, from multiple areas of the business. The Steering Committee meets quarterly and reports to senior management regarding the progress of specific cybersecurity objectives. Cross-enterprise action teams will be formed, as needed, to manage and implement key decisions of the Steering Committee. A strong partnership exists between our information technology, finance, operations, internal audit, and legal departments for the purpose of addressing identified issues in a timely manner and reporting incidents as required.

The Nominating & Governance Committee, which is comprised entirely of independent directors, has primary responsibility for oversight of our initiatives, policies, and performance regarding risk management matters, including information security, cybersecurity, business continuity, and data protection and privacy. The Committee generally meets at least quarterly and, together with members of senior management, reviews assessments of cyber risks, the threat landscape, and our risk mitigation and governance strategies. The Nominating & Governance Committee and senior management brief the full board of directors of the Company, as appropriate, on cybersecurity matters discussed during committee meetings.

Management has established processes to assess the materiality of cybersecurity incidents, considering operational, financial, legal/regulatory, and reputational impacts, and to determine whether a series of otherwise immaterial incidents is material in the aggregate. These processes support timely disclosure and reporting under applicable SEC rules.

While some of our third-party service providers have experienced cybersecurity incidents and have experienced threats to their data and systems, as of the date of this Annual Report, we are not aware of any cybersecurity threats that have materially affected or are reasonably likely to materially affect us. Similarly, we intend to periodically evaluate and/or adjust internal policies governing our use of artificial intelligence technologies and our compliance with applicable data privacy laws and regulations. However, we face certain ongoing risks from cybersecurity threats, that, if realized, may, among other things, cause material disruptions to our operations, which may materially affect us, including our business strategy, results of operations, and/or financial condition. For more information about these risks, see the risk factor titled, "Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions" under Item 1A of Part I of this Annual Report.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business — Our Areas of Operation" and "—Our Oil and Natural Gas Data" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations" contained herein.

ITEM 3. LEGAL PROCEEDINGS

We are and may be, from time to time, party to various legal proceedings, government investigations and environmental proceedings. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdictions in which we operate. Information pertaining to legal proceedings is described in Note 17, "Commitments and Contingencies — Litigation and Environmental" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report, which is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our Common Stock is listed on the NYSE under the trading symbol "AMPY" and has been trading since August 7, 2019.

As of February 28, 2026, we had 41,265,055 shares of our Common Stock outstanding. As of February 28, 2026, we had twenty-two record holders of our Common Stock, based on information provided by our transfer agent.

Dividends Policy

While we may decide to pay cash dividends in the future, we have not paid, nor do we currently intend to pay, any cash dividends on our Common Stock. Future dividends, if any, are subject to the terms of our Revolving Credit Facility and discretionary approval by the Board.

Securities Authorized for Issuance Under Equity Compensation Plan

See the information incorporated by reference in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" for information regarding shares of our Common Stock authorized for issuance under our stock compensation plans, which information is incorporated herein by reference.

Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company's repurchases of shares of its Common Stock during the fourth quarter of 2025.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (1) (In thousands)
Common Shares Repurchased (1)				
October 1, 2025 - October 31, 2025	3,020	$ 5.19	—	n/a
November 1, 2025 - November 30, 2025	51,569	$ 4.89	—	n/a
December 1, 2025 - December 31, 2025	92,153	$ 5.09	—	n/a

(1) Common shares are generally net-settled by shareholders to cover the required withholding tax upon vesting. The Company repurchased the remaining vesting shares on the vesting date at current market price. See Note 12, "Equity-based Awards" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report, which is incorporated herein by reference.

ITEM 6. Reserved

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis ("MD&A") of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" contained herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are discussed in "Risk Factors" contained in Part I, Item 1A. of this report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-Looking Statements" in the front of this Annual Report.

Overview

We operate in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on the reportable business segment as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries.

Our assets have historically consisted primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana, and the Eagle Ford (Non-op). During 2025, we completed several divestiture transactions, including the sale of our non-operated Eagle Ford assets in July 2025, our East Texas/North Louisiana assets in December 2025 and our Oklahoma assets in December 2025. As of the date of this Annual Report, our remaining properties consist solely of Bairoil and Beta.

Production and Operation Update

Total production for the Company in 2025 was composed of approximately 45% oil, 39% natural gas and 16% NGLs compared to 43% oil, 39% natural gas and 18% NGLs in 2024. The change in our oil production was primarily related to the development of wells at Beta. We had a decrease of 10% in oil and natural gas sales primarily due to lower volumes and decrease in oil prices. Average realized sales price per Boe was $38.03 for 2025 compared to $39.61 for 2024.

Our estimated proved reserves decreased to 38.1 MMBoe in 2025 compared to 93.0 MMBoe in 2024. The decrease was primarily due to 53.2 MMBoe for divestitures reserves. In addition, the change in reserves were impacted by changes in commodity prices, partially offset by upward reserves revisions due to performance, and reserve additions due to new locations specifically related to Beta.

As of December 31, 2025, we are the operator of record for properties containing 100% of our total estimated proved reserves.

Recent Developments

Reduction in Force

During the fourth quarter of 2025 and throughout the first quarter of 2026, certain employees were impacted by a workforce reduction resulting in the involuntary termination of 36 employees across the Company. The Company recorded $6.8 million of severance expense for the year ended December 31, 2025, which is included in "general and administrative expense" in the Company's Consolidated Statement of Operations.

Amended Revolving Credit Facility

On December 31, 2025, OLLC entered into the Borrowing Base Redetermination, Commitment Increase and Second Amendment to Amended and Restated Credit Agreement (the "Second Amendment"), among OLLC, Amplify Acquisitionco LLC, the guarantors party thereto, the lenders party thereto and Citizens Bank, N.A., as administrative agent for the lenders. The Second Amendment amends the Amended and Restated Credit Agreement, dated July 31, 2023 (as amended, the "Credit Agreement"), to, among other things: (i) set the Borrowing Base to $25.0 million, with elected commitments of $15.0 million and (ii) extend the maturity date under the Credit Agreement to December 31, 2028. We had no amounts outstanding at December 31, 2025.

Revolution Purchase and Sale Agreement

On November 4, 2025, Amplify Oklahoma Operating LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Amplify Oklahoma"), Magnify Energy Services LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Magnify" and, together with Amplify Oklahoma, the "Revolution Sellers") and OLLC, for certain limited purposes, entered into a purchase and sale agreement (the "Revolution Purchase and Sale Agreement") with Revolution Resources III, LLC, a Delaware limited liability company ("Revolution"), pursuant to which the Revolution Sellers sold to Revolution certain assets of the Revolution Sellers, which include, among other things, the Revolution Sellers' right, title and interest in and to certain specified oil and gas properties and equipment within or related to certain designated lands in Oklahoma (the "Revolution Asset Sale") for a cash purchase price of $92.5 million, subject to estimated post-closing adjustments under the Revolution Purchase and Sale Agreement. The Revolution Asset Sale closed on December 29, 2025, with an effective date of October 1, 2025. We received net proceeds of $88.7 million from the Revolution Asset Sale. The proceeds from the divestiture were used to reduce borrowings under our Revolving Credit Facility. In connection with this transaction, we performed an assessment of the fair value of the net book value and determined that the assets were impaired, and as such, we recorded impairment expense of $34.0 million to write down those assets to the estimated purchase price less cost to sell.

EQV Purchase and Sale Agreement

On October 28, 2025, OLLC and Magnify (together with OLLC, the "EQV Sellers"), entered into a purchase and sale agreement (as subsequently amended, the "EQV Purchase and Sale Agreement") with EQV Alpha LLC, a Delaware limited liability company ("Alpha"), pursuant to which the EQV Sellers sold to Alpha certain assets of the EQV Sellers, which include, among other things, the EQV Sellers' right, title and interest in and to certain specified oil and gas properties and equipment within or related to certain designated lands in East Texas and Louisiana (the "EQV Asset Sale") for a cash purchase price of $122.0 million, subject to estimated post-closing adjustments under the EQV Purchase and Sale Agreement. The EQV Asset Sale closed on December 23, 2025, with an effective date of October 1, 2025. We received net proceeds of $111.6 million from the EQV Asset Sale. The proceeds from the divestiture were used to reduce borrowings under our Revolving Credit Facility.

East Texas Haynesville Monetization

On October 2, 2025, the Company entered into a purchase and sale agreement to sell its remaining interest in certain units with rights in the Cotton Valley and Haynesville basins in Harrison County, Texas, generating $5.3 million in net proceeds from the transactions. The sale closed on October 24, 2025, with an effective date of October 1, 2025.

Other 2025 Developments

Other 2025 Divestitures

In July 2025, we closed a transaction to divest our non-operated Eagle Ford assets for a total purchase price of $23.0 million, excluding $1.9 million of final post-closing adjustments, resulting in a final adjusted purchase price of $21.1 million. In connection with this transaction, we performed an assessment of the fair value of the net book value and determined that the assets were impaired, and as such, we recorded impairment expense of $8.4 million to write down those assets to the estimated purchase price less cost to sell.

Throughout 2025, we had other divestitures where we sold certain rights and interests in the Cotton Valley and Haynesville basins generating approximately $7.8 million in net proceeds from such transactions.

Leadership Changes

On July 21, 2025, the Company, and Mr. Martyn Willsher, the Company's former President, Chief Executive Officer and member of the Company's board of directors (the "Board"), agreed that (i) Mr. Willsher's roles as President and Chief Executive Officer of the Company and a member of the Board terminated effective July 22, 2025 (the "Transition Date"), and (ii) Mr. Willsher assumed the non-executive employee role of Special Advisor to the Company on the Transition Date.

In connection with the transition of Mr. Willsher's role, the Company and Mr. Willsher entered into a Transition and Separation Agreement (the "Transition Agreement"), effective as of the Transition Date. Pursuant to the terms of the Transition Agreement, Mr. Willsher served as Special Advisor to the Company until December 31, 2025.

Appointment of Chief Executive Officer and Director

On July 21, 2025, the Board appointed Mr. Daniel Furbee, previously the Company's Senior Vice President and Chief Operating Officer, to Chief Executive Officer and as a member of the Board, effective as of the Transition Date. In connection with Mr. Furbee's appointment as Chief Executive Officer, Mr. Furbee and the Company entered into a performance-based restricted stock units award agreement.

Appointment of President and Chief Financial Officer

On July 21, 2025, the Board appointed Mr. James Frew, previously the Company's Senior Vice President and Chief Financial Officer, to President and Chief Financial Officer, effective as of the Transition Date.

Appointment of Vice President and Chief Accounting Officer

On November 14, 2025, Mr. Eric Dulany and the Company mutually agreed Mr. Dulany's tenure as Vice President and Chief Accounting Officer would end, effective immediately. Mr. Dulany's departure did not result from any disagreement with the Company, the Company's management or the Board. On November 14, 2025, the Board appointed Ms. Natasha France, to serve as Vice President and Chief Accounting Officer of the Company, effective immediately.

Termination of Contemplated Merger with Juniper Capital

On January 14, 2025, the Company entered into an Agreement and Plan of Merger, as subsequently amended (the "Merger Agreement") with Amplify DJ Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of the Company ("First Merger Sub"), Amplify PRB Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of Amplify Energy ("Second Merger Sub"), North Peak Oil & Gas, LLC, a Delaware limited liability company ("NPOG"), Century Oil and Gas Sub-Holdings, LLC, a Delaware limited liability company ("COG" and, together with NPOG, the "Acquired Companies"), and, solely for the limited purposes set forth in the Merger Agreement, Juniper Capital Advisors, L.P. ("Juniper Capital") and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the effective time of the Contemplated Mergers (as defined below), it was contemplated that (i) NPOG would merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (ii) COG would merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement (clauses (i) and (ii), together, the "Contemplated Mergers").

On April 25, 2025, pursuant to Section 8.1(a) of the Merger Agreement, the Company and the Acquired Companies entered into a mutual termination agreement (the "Termination Agreement") to terminate the Merger Agreement (the "Termination"), effective immediately. As a result of the Termination Agreement, the Merger Agreement is of no further force and effect.

Industry Trends

For a discussion of how industry trends have affected and may continue to affect our business and financial condition, see the discussion under the heading "Industry Trends" in Part I, Item 1 of this report, as well as the Risk Factors set forth in Part I, Item 1A of this report.

Business Environment and Operational Focus

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including: (i) production volumes; (ii) realized prices on the sale of our production; (iii) cash settlements on our commodity derivatives; (iv) lease operating expense; (v) gathering, processing and transportation; (vi) general and administrative expense; and (vii) Adjusted EBITDA.

Production Volumes

Production volumes directly impact our results of operations. For more information about our volumes, see "— Results of Operations" below.

Realized Prices on the Sale of Oil and Natural Gas

We market our oil and natural gas production to a variety of purchasers based on regional pricing. The relative prices of oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, realized prices are heavily influenced by product quality and location relative to consuming and refining markets.

Natural Gas. The NYMEX-Henry Hub future price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices realized from the sale of natural gas can differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (1) the Btu content of natural gas, which measures its heating value, and (2) the percentage of sulfur, CO_2 and other inert content by volume. Natural gas with a high Btu content ("wet" natural gas) sells at a premium to natural gas with low Btu content ("dry" natural gas) because it yields a greater quantity of NGLs. Natural gas with low sulfur and CO_2 content sells at a premium to natural gas with high sulfur and CO_2 content because of the added cost required to separate the sulfur and CO_2 from the natural gas to render it marketable. Wet natural gas may be processed in third-party natural gas plants, where residue natural gas as well as NGLs are recovered and sold. At the wellhead, our natural gas production typically has an average energy content greater than 1,000 Btu. The dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the produced natural gas' proximity to the major consuming markets to which it is ultimately delivered. Historically, these index prices have generally been at a discount to NYMEX-Henry Hub natural gas prices.

Oil. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The ICE Brent futures price is a widely used global price benchmark for oil. The actual prices realized from the sale of oil can differ from the quoted NYMEX-WTI price as a result of quality and location differentials. Quality differentials result from the fact that crude oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (1) the oil's API gravity and (2) the oil's percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value and, therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content ("sweet" oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil ("sour" oil).

Location differentials result from variances in transportation costs based on the produced oil's proximity to the major consuming and refining markets to which it is ultimately delivered. Oil that is produced close to major consuming and refining markets, such as near Cushing, Oklahoma, is in higher demand as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major consuming and refining markets normally realizes a higher price (i.e., a lower location differential).

The oil produced from our onshore properties is a combination of sweet and sour oil, which varies by location. This oil is typically sold at the NYMEX-WTI price, adjusted for quality and transportation differential, depending primarily on location and purchaser. The oil produced from our offshore properties is heavy and sour oil and was sold based on refiners' posted prices for ICE Brent for the year ended December 31, 2025.

Price Volatility. In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. The following table shows the low and high commodity future index prices for the periods indicated:

	High	Low
For the Year Ended December 31, 2025:		
NYMEX-WTI oil future price range per Bbl	$ 80.04	$ 55.27
NYMEX-Henry Hub natural gas future price range per MMBtu	$ 5.29	$ 2.70
ICE Brent oil future price range per Bbl	$ 82.03	$ 58.92

Commodity Derivative Contracts. Our hedging activities are intended to support oil, natural gas and NGL prices at targeted levels and to manage our exposure to commodity price fluctuations. The covenants in our Revolving Credit Facility require us to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 25%–75%, depending on availability under the Revolving Credit Facility, of our estimated production from proved developed producing reserves over a one-year period at any given point of time. We may, however, from time-to-time hedge more or less than this approximate range. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Principal Components of Cost Structure

- *Lease operating expense*. These are the day-to-day costs incurred to maintain production of our oil, natural gas, and NGLs. Such costs include utilities, direct labor, water injection and disposal, the cost of CO_2 injection, chemicals, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services and activities performed during a specific period.

- *Gathering, processing and transportation.* These are costs incurred to deliver production of our oil, natural gas, and NGLs to the market. Cost levels of these expenses can vary based on the volume of oil, natural gas, and NGLs production.

- *Taxes other than income*. These consist of production, ad valorem, NOx credits, and franchise taxes. Production taxes are paid on produced oil, natural gas, and NGLs based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. We take advantage of credits and exemptions in the various taxing jurisdictions where we operate. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties. Franchise taxes are privilege taxes levied by states that are imposed on companies, including limited liability companies and partnerships, which gives the businesses the right to be chartered or operate within that state.

- *Depreciation, depletion and amortization*. Depreciation, depletion and amortization ("DD&A") includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop oil and natural gas properties. As a "successful efforts" company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

- *Impairment expense.* Proved properties are impaired whenever the net carrying value of the properties exceed their estimated undiscounted future cash flows. Unproved properties are impaired based on time or geologic factors.

- *General and administrative expense*. These costs include overhead, including payroll and benefits for certain employees, costs of maintaining headquarters, costs of managing production and development operations, compensation expenses associated with certain long-term incentive-based plans, audit and other professional fees and legal compliance expenses.

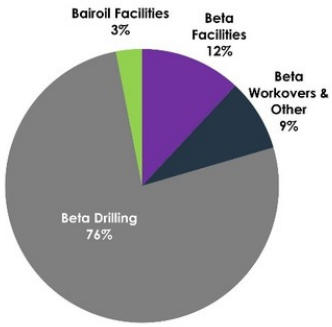
- *Interest expense, net.* Historically, we have financed a portion of our working capital requirements, capital development and acquisitions with borrowings under our Revolving Credit Facility. We incur interest expense that is affected by both fluctuations in interest rates and financing decisions. These costs also include capitalized interest, the amortization and write off of deferred financing costs and the amortization of surety bonds.

- *Income tax expense.* We are a corporation subject to federal and certain state income taxes.

Outlook

Based on our current plans, our capital expenditure program for the full year 2026 is expected to be approximately $45.0 million to $65.0 million. Our capital expenditure program for 2026 is allocated among our remaining properties with 97% allocated to Beta and 3% allocated to Bairoil. The charts below detail the allocation of capital by investment type based on the midpoint of our 2026 capital expenditure range.

2026 CAPEX by Investment



As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices and other factors. We anticipate funding our 2026 capital program from internally generated cash flow and cash on hand.

Critical Accounting Policies and Estimates

The methods, estimates and judgments we use in applying our critical accounting policies have a significant impact on the results we report in our Consolidated Financial Statements. We evaluate our estimates and judgments on an on-going basis. We base our estimates on historical experience and on assumptions that we believe to be reasonable under the circumstances. Our experience and assumptions form the basis for our judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results may vary from what we anticipate and different assumptions or estimates about the future could change our reported results.

Oil and Natural Gas Properties. We use the successful efforts method of accounting for our oil and natural gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

We review the carrying value of our oil and natural gas properties, including support equipment for impairments quarterly or when events and circumstances indicate the carrying value of our properties may not be recoverable. Such indications could be the result of downward revisions of the reserve estimates, less than expected production or drilling results, higher operating and development costs, or lower commodity prices. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

We believe accounting for oil and natural gas properties is a critical accounting estimate because the policies discussed above impact the carrying value of our properties and involve significant judgments about the impact of future events on our estimated cash flows. Future events and circumstances currently unknown to us could require future impairments to our properties and materially change the carrying value of our properties.

Oil and Natural Gas Reserves. Proved oil and natural gas reserves are estimated in accordance with the rules established by the SEC and FASB. The rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalation in future years except by contractual arrangements. Our reserve estimates are prepared by our reserve engineers and audited by independent engineers.

Our reserve estimates are updated at least annually using geological and reserve data, as well as production performance data. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates. A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimate may impact the outcome of our assessment of oil and natural gas producing properties for impairment. We cannot predict what reserve revisions may be required in future periods.

We believe the estimate of oil and natural gas reserves is a critical accounting estimate because we must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the timing of development expenditures. Future results of operations for any period could be materially affected by changes in our assumptions. Significant changes in these estimates could result in a change to our estimated reserves, which could lead to a material change to our production depletion expense.

Derivative Financial Instruments. Our commodity derivative financial instruments are used to reduce the impact of oil and natural gas price fluctuations. We record our derivative instrument in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions. Significant changes to the market value of derivative instruments due to the volatility of oil and natural gas prices can have an impact on our financial condition and results of operations.

Contingencies Accounting. A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. Although we are insured against various risks to the extent we believe is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued when environmental remediation efforts are probable and the costs can be reasonably estimated. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals.

We believe contingencies accounting is a critical accounting estimate because we must assess the probability of the loss related to the contingency.

Income Tax. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards.

In assessing the carrying value of our net deferred tax assets, we consider the realizability of our deferred tax assets each reporting period. The realization of any deferred tax asset is dependent upon the generation of future taxable income sufficient to demonstrate our ability to utilize the deferred tax asset in the period in which the temporary differences become deductible or in a future period prior to expiration. We considered all available evidence, including cumulative historical losses (defined as pre-tax earnings as adjusted for permanent tax adjustment), scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretation of tax laws and the resolution of any tax audits could significantly impact the amounts provided for income taxes in our Consolidated Financial Statements.

We believe accounting for income taxes is a critical accounting estimate because the policies discussed above in assessing the carrying value of our net deferred tax assets require estimates and judgements about the impact of future events on our projected taxable income, the results of which can have a material impact on our Consolidated Financial Statements.

In future periods, we may demonstrate cumulative historical losses for the previous three fiscal years, which could significantly impact our need for a valuation allowance. Any increase in the valuation allowance would increase our income tax expense in the Consolidated Statements of Operations.

Results of Operations

The results of operations for the years ended December 31, 2025 and 2024 have been derived from our Consolidated Financial Statements.

Factors Affecting the Comparability of the Historical Financial Results

- The sale of our non-operated Eagle Ford assets in July 2025 for $23.0 million, excluding $1.9 million of final post-closing adjustments, resulting in a final adjusted purchase price of $21.1 million.
- The sale of all of our assets located in East Texas/North Louisiana in December 2025 for $122.0 million, subject to estimated post-closing adjustments.
- The sale of all of our assets located in Oklahoma in December 2025 for $92.5 million, subject to estimated post-closing adjustments.
- Other sales of interest in certain units with rights in the Cotton Valley and Haynesville basins during 2025 for $13.6 million.

As a result of the factors listed above, the historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated.

	For the Year Ended December 31,	
	2025	2024
	($ In thousands)	
Oil and natural gas sales	$ 256,097	$ 282,992
Other revenues	7,264	11,689
Lease operating expense	141,324	142,950
Gathering, processing and transportation	17,795	18,427
Taxes other than income	15,870	20,895
Depreciation, depletion and amortization	32,484	32,586
Impairment expense	42,450	—
General and administrative expense	52,056	35,895
Loss (gain) on commodity derivative instruments	(28,397)	2,047
Pipeline incident loss	2,423	3,859
(Gain) loss on sale of properties	(99,548)	(1,367)
Interest expense, net	15,577	14,599
Income tax (expense) benefit - current	1,377	(232)
Income tax (expense) benefit - deferred	(18,248)	(2,196)
Net income (loss)	43,968	12,946
Oil and natural gas revenues:		
Oil sales	$ 182,764	$ 220,380
NGL sales	21,379	26,789
Natural gas sales	51,954	35,823
Total oil and natural gas revenues	$ 256,097	$ 282,992
Production volumes:		
Oil (MBbls)	3,008	3,060
NGLs (MBbls)	1,067	1,278
Natural gas (MMcf)	15,948	16,836
Total (MBoe)	6,733	7,144
Average net production (MBoe/d)	18.4	19.5
Average realized sales price (excluding commodity derivatives):		
Oil (per Bbl)	$ 60.76	$ 72.01
NGL (per Bbl)	20.03	20.96
Natural gas (per Mcf)	3.26	2.13
Total (per Boe)	$ 38.03	$ 39.61
Average unit costs per Boe:		
Lease operating expense	$ 20.99	$ 20.01
Gathering, processing and transportation	2.64	2.58
Taxes other than income	2.36	2.92
General and administrative expense	7.73	5.02
Depletion, depreciation and amortization	4.82	4.56

For the year ended December 31, 2025 compared to the year ended December 31, 2024

Net income of $44.0 million compared to net income of $12.9 million was recorded for the year ended December 31, 2025 and 2024, respectively.

Oil, natural gas and NGL revenues were $256.1 million and $283.0 million for the year ended December 31, 2025 and 2024, respectively. Average net production volumes were approximately 18.4 MBoe/d and 19.5 MBoe/d for the year ended December 31, 2025 and 2024, respectively. The average realized sales price was $38.03 per Boe and $39.61 per Boe for the year ended December 31, 2025 and 2024, respectively. The change in average realized sales price was due to lower realized sales prices for oil, partially offset by higher realized sales prices for natural gas.

Other revenues were $7.3 million and $11.7 million for the year ended December 31, 2025 and 2024, respectively. For the year ended December 31, 2025, other revenues consisted of iodine sales of $2.7 million and service revenues of $4.1 million with respect to our wholly owned subsidiary, Magnify Energy Services ("Magnify"). For the year ended December 31, 2024, other revenues consisted of iodine sales of $2.4 million, and service revenues of $3.1 million for Magnify. Additionally, for the year ended December 31, 2024, we recorded a revenue suspense release of $4.8 million.

Lease operating expense was $141.3 million and $143.0 million for the year ended December 31, 2025 and 2024, respectively. The change in lease operating expense was primarily due to the divestiture of our non-operated Eagle Ford assets and lower electricity and CO_2 costs at Bairoil starting in the fourth quarter, partially offset by increased workover expense at Beta. On a per Boe basis, lease operating expense was $20.99 and $20.01 for the year ended December 31, 2025 and 2024, respectively.

Gathering, processing and transportation expenses were $17.8 million and $18.4 million for the year ended December 31, 2025 and 2024, respectively. On a per Boe basis, gathering, processing and transportation expenses were $2.64 and $2.58 for the year ended December 31, 2025 and 2024, respectively. The decrease in gathering, processing and transportation expense was primarily driven by lower volumes.

Taxes other than income were $15.9 million and $20.9 million for the year ended December 31, 2025 and 2024, respectively. On a per Boe basis, taxes other than income were $2.36 and $2.92 for the year ended December 31, 2025 and 2024, respectively. The change in taxes other than income was primarily related to a reduction in production taxes due to lower volumes, the divestiture of our non-operated Eagle Ford assets, lower year-over-year revenues and a decrease in waste emission charges.

DD&A expense was $32.5 million and $32.6 million for the year ended December 31, 2025 and 2024, respectively.

General and administrative expense was $52.1 million and $35.9 million for the year ended December 31, 2025 and 2024, respectively. The change in general and administrative expense is primarily related to (i) an increase of $8.3 million in acquisition and divestiture costs, (ii) an increase of $1.5 million in stock compensation expense; (iii) an increase of $1.1 million in bad debt expense, (iv) an increase of $6.4 million in severance expense and (v) an increase of $0.9 million in legal expense; partially offset by (i) a decrease of $1.0 million in salaries and other payroll benefits, and (ii) a decrease of $0.3 million in professional services.

Acquisition and divestiture related expenses included in general and administrative expenses included the following for the periods indicated below (in thousands):

	For the Year Ended December 31,	
	2025	2024
Cost incurred related to the contemplated merger with Juniper Capital	$ 2,769	$ 1,383
Cost incurred related to the EQV Asset Sale and the Revolution Asset Sale	5,399	—
Other acquisition and divestitures expenses	1,722	250
	$ 9,890	$ 1,633

Net loss (gain) on commodity derivative instruments for the year ended December 31, 2025 was a gain of $28.4 million which consisted of a $12.2 million increase in the fair value of open positions and $16.8 million in cash settlements received on expired positions, partially offset by $0.6 million in cash settlements paid on terminated derivative instruments. Net losses on commodity derivative instruments of $2.0 million were recognized for the year ended December 31, 2024, and consisted of a $20.5 million decrease in the fair value of open positions, partially offset by $0.8 million of cash settlements received on terminated derivative instruments and $17.6 million in cash settlements received on expired positions.

Given the volatility of commodity prices, it is not possible to predict future reported unrealized mark-to-market net gains or losses and the actual net gains or losses that will ultimately be realized upon settlement of the hedge positions in future years. If commodity prices at settlement are lower than the prices of the hedge positions, the hedges are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the hedge positions, the hedges are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

Pipeline incident loss was $2.4 million and $3.9 million for the year ended December 31, 2025 and 2024. The $2.4 million reflects certain expenses not expected to be recovered under an insurance policy. See Note 17 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

(Gain) loss on sale of properties was a gain of ($99.5) million and ($1.4) million for the year ended December 31, 2025 and 2024. See additional information discussed in Note 4 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Interest expense, net was $15.6 million and $14.6 million for the year ended December 31, 2025 and 2024, respectively. The change was primarily related to $1.5 million for write-off of deferred issuance costs.

Average outstanding borrowings under our Revolving Credit Facility were $124.9 million and $120.9 million for the year ended December 31, 2025 and 2024, respectively.

Current income tax (expense) benefit was $1.4 million and ($0.2) million for the year ended December 31, 2025 and 2024, respectively. See additional information discussed in Note 18 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Deferred income tax benefit (expense) was ($18.2) million and ($2.2) million for the year ended December 31, 2025 and 2024, respectively. See additional information discussed in Note 18 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

For the year ended December 31, 2024 compared to the year ended December 31, 2023

Information related to the comparison of our discussion of the results of operations for the year ended December 31, 2024, compared to the year ended December 31, 2023, is included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the year ended December 31, 2024 ("2024 Form 10-K") filed with the SEC and is incorporated by reference into this Annual Report.

Non-GAAP Financial Measures

We include in this report the non-GAAP financial measures for Adjusted Net Income (Loss) and Adjusted EBITDA and provide our reconciliation of net income (loss) to Adjusted Net Income (Loss) and a reconciliation of net cash flow from operating activities to Adjusted EBITDA, our most directly comparable financial measure calculated and presented in accordance with GAAP.

Adjusted Net Income (Loss)

We define Adjusted Net Income (Loss) as net income (loss) adjusted for unrealized loss (gain) on commodity derivative instruments, acquisition & divestiture related expenses, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our federal statutory tax rate. Adjusted Net Income (Loss) excludes the impact of unusual and infrequent items affecting earnings that can vary widely and unpredictably, including unrealized derivative gains and losses. This measure is not meant to disassociate these items from management's performance but rather is intended to provide helpful information to investors interested in comparing our performance between periods. Adjusted Net Income (Loss) is not considered to be an alternative to net income (loss) reported in accordance with GAAP.

Reconciliation of Net Income (Loss) to Adjusted Net Income (Loss)

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Net (loss) income	$ 43,968	$ 12,946
Unrealized loss (gain) on commodity derivative instruments	(12,235)	20,457
Acquisition and divestiture-related expenses	9,890	1,633
Impairment expense	42,450	—
Non-recurring costs:		
(Gain) loss on sale of properties	(99,548)	(1,367)
Tax effect of adjustments [1]	9,914	(56)
Adjusted net income (loss)	$ (5,561)	$ 33,613

(1) The federal statutory rates were utilized for all periods presented.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including gains or losses on interest rate derivative contracts;
- Income tax expense;
- DD&A;
- Impairment of goodwill and long-lived assets (including oil and natural gas properties);
- Accretion of asset retirement obligations ("AROs");
- Loss on commodity derivative instruments;
- Cash settlements received on expired commodity derivative instruments;
- Losses on sale of assets and other, net;
- Share-based compensation expenses;
- Exploration costs;
- Acquisition and divestiture related expenses;
- Amortization of gain associated with terminated commodity derivatives;
- Severance payments;
- Bad debt expense; and
- Other non-routine items that we deem appropriate.

Less:

- Interest income;
- Income tax benefit;
- Gain on expired commodity derivative instruments;
- Cash settlements paid on expired commodity derivative instruments;
- Gains on sale of assets and other, net; and
- Other non-routine items that we deem appropriate.

We are required to comply with certain Adjusted EBITDA-related metrics under our Revolving Credit Facility.

We believe that Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure.

Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

In addition, management uses Adjusted EBITDA to evaluate actual cash flow, develop existing reserves or acquire additional oil and natural gas properties.

The following tables present a reconciliation of the Company's net income (loss) and cash flows operating activities to Adjusted EBITDA, our most directly comparable GAAP financial measures, for each of the periods indicated.

Reconciliation of Net Income (Loss) to Adjusted EBITDA

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Net income (loss)	$ 43,968	$ 12,946
Interest expense, net	15,577	14,599
Income tax expense (benefit) - current	(1,377)	232
Income tax expense (benefit) - deferred	18,248	2,196
Impairment expense	42,450	—
DD&A	32,484	32,586
Accretion of AROs	8,861	8,438
Loss (gain) on commodity derivative instruments	(28,397)	2,047
Cash settlements (paid) received on expired commodity derivative instruments	16,784	17,617
(Gain) loss on sale of properties	(99,548)	(1,367)
Share-based compensation expense	8,292	6,799
Acquisition and divestiture related expenses	9,890	1,633
Severance payments	6,814	—
Amortization of gain associated with terminated commodity derivatives	636	159
Pipeline incident loss	2,423	3,859
Loss on settlement of AROs	1,070	470
Exploration costs	32	61
Bad debt expense	1,188	80
Other	800	686
Adjusted EBITDA[1]	$ 80,195	$ 103,041

(1) Adjusted EBITDA includes a revenue suspense release of $0.4 million and $8.4 million for the year ended December 31, 2025 and 2024, respectively.

Reconciliation of Net Cash from Operating Activities to Adjusted EBITDA

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Net cash provided by operating activities	$ 49,200	$ 51,293
Changes in working capital	(3,561)	32,272
Interest expense, net	15,577	14,599
(Gain) loss on sale of property	—	(1,367)
Acquisition and divestiture related expenses	9,890	1,633
Pipeline incident loss	2,423	3,859
Severance payments	6,814	—
Plugging and abandonment cost	2,344	1,640
Amortization and write-off of deferred financing fees	(2,676)	(1,233)
Cash settlements paid (received) on terminated derivatives	93	(793)
Amortization of gain associated with terminated commodity derivatives	636	159
Income tax expense (benefit) - current	(1,377)	232
Exploration costs	32	61
Other	800	686
Adjusted EBITDA[1]	$ 80,195	$ 103,041

(1) Adjusted EBITDA includes a revenue suspense release of $0.4 million and $8.4 million for the year ended December 31, 2025 and 2024, respectively.

Liquidity and Capital Resources

Overview. During the year ended December 31, 2025, we significantly enhanced our liquidity position primarily through the completion of several divestitures. Proceeds from these transactions materially strengthened our cash position and enabled us to fully repay all outstanding borrowings under our Revolving Credit Facility. As a result of these actions, we ended the year with approximately $60.7 million in cash and cash equivalents on December 31, 2025.

The divestitures reduced our ongoing capital requirements and streamlined our operating profile, which we believe positions us with greater financial flexibility. Following the payoff of the debt facility, we no longer have any outstanding borrowings.

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our primary sources of liquidity and capital resources have historically been cash flows generated by operating activities, borrowings under our Revolving Credit Facility, and equity and debt capital markets. However, future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all. We anticipate funding our 2026 capital program from cash on hand and internally generated cash flow but retain the flexibility to utilize borrowings under debt facilities available to us, and/or to access the debt and equity capital markets. As we pursue reserve and production growth, we plan to monitor which capital resources, including equity and debt financings, are available to us to meet our future financial obligations, planned capital expenditure activities and liquidity requirements.

Based on our current oil price expectations, we believe our cash flows provided by operating activities and availability under our Revolving Credit Facility will provide us with the financial flexibility necessary to meet our cash requirements, including normal operating needs, and to pursue our currently planned 2026 development activities. We believe that existing cash and cash equivalents, any positive cash flows from operations and available borrowings under our Revolving Credit Facility will be sufficient to support working capital, capital expenditures and other cash requirements for at least the next 12 months and, based on our current expectations, for the foreseeable future thereafter.

Termination of Contemplated Merger with Juniper Capital. In connection with the Contemplated Mergers, on April 25, 2025, pursuant to Section 8.1(a) of the Merger Agreement, the Company and the Acquired Companies entered into the Termination Agreement to terminate the Merger Agreement, effective immediately. In accordance with the terms of the Termination Agreement, the Company made a cash payment to the Acquired Companies in lieu of any termination fee which might have otherwise been payable pursuant to the Merger Agreement in the amount of $800,000 as payment for certain of the Acquired Companies' expenses. The Company incurred professional fees and expenses of approximately $3.6 million and $1.4 million for the year ended December 31, 2025 and 2024, respectively, in connection with the Contemplated Mergers and the Termination. For additional information regarding the Termination, see Notes 4 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Capital Markets. We do not currently anticipate any near-term capital markets activity, but we will continue to evaluate the availability of public debt and equity for funding potential future growth projects and acquisition activity.

Hedging. Commodity hedging has been and remains an important part of our strategy to reduce cash flow volatility. Our hedging activities are intended to support oil prices at targeted levels and to manage our exposure to commodity price fluctuations. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 25%−75%, depending on availability under the Revolving Credit Facility, of our estimated production from total proved developed producing reserves over a one-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices. Non-performance by a customer could also result in losses.

Capital Expenditures. Our total capital expenditures were approximately $82.3 million for the year ended December 31, 2025, which were primarily related to the development program at Beta and non-operated drilling and completion activities in East Texas and the Eagle Ford.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable as well as the classification of our debt outstanding. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2025, we had working capital (excluding commodity derivatives) of $57.1 million primarily as the result of (i) a cash and cash equivalents balance of $60.7 million, (ii) an accounts receivable balance of $30.1 million and (iii) prepaid expenses and other current assets balance of $24.4 million, partially offset by (i) an accrued liabilities balance of $34.5 million, (ii) an accounts payable balance of $17.9 million, and (iii) a revenues payable balance of $5.6 million.

Debt Agreements

Revolving Credit Facility. On December 31, 2025, OLLC, as borrower, amended the Revolving Credit Facility with Citizens Bank, as administrative agent to, among other things: (i) set the Borrowing Base to $25.0 million with elected commitments of $15.0 million and (ii) extend the maturity date under the Credit Agreement to December 31, 2028. At December 31, 2025, the Company had no loans outstanding under the Revolving Credit Facility.

As of December 31, 2025, we had approximately $15.0 million of available borrowings under our Revolving Credit Facility.

As of December 31, 2025, we were in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with our Revolving Credit Facility.

For additional information regarding our Revolving Credit Facility, see Note 9 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Material Cash Requirements

Contractual commitments. We have contractual commitments under our debt agreements, including interest payments and principal payments. See Note 9 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Lease Obligations. We have operating leases for office and warehouse spaces, office equipment, compressors and surface rentals related to our business obligations. As of December 31, 2025, our future commitments under these contracts were $1.4 million in 2026, $1.0 million in 2027, $0.7 million in 2028, $0.7 million in 2029 and $0.4 million thereafter. See Note 13 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Sinking fund payments. We have a funding requirement to fund a trust account to comply with supplemental regulatory bonding requirements related to our decommissioning obligations for our Beta production facilities. As of December 31, 2025, our future commitments under this agreement were $9.0 million per year for years 2026 through 2033. See Note 17 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated. The cash flows for the years ended December 31, 2025 and 2024, have been derived from our Consolidated Financial Statements. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under "Item 8. Financial Statements and Supplementary Data" contained herein.

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Net cash provided by operating activities	$ 49,200	$ 51,293
Net cash provided by (used in) investing activities	141,298	(82,034)
Net cash provided by (used in) financing activities	(129,832)	9,995

For the year ended December 31, 2025 compared to the year ended December 31, 2024

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes, and operating costs. Net cash provided by operating activities was $49.2 million and $51.3 million for the year ended December 31, 2025 and 2024, respectively. Production volumes decreased to 18.4 MBoe/d in 2025 from 19.5 MBoe/d in 2024, and the average realized sales price decreased to $38.03 per Boe in 2025 from $39.61 per Boe in 2024. The change in realized sales price was due to lower realized sales prices for oil, partially offset by higher realized sales prices for natural gas.

Net cash provided by operating activities for the year ended December 31, 2025 included $16.8 million of cash received on expired derivative instruments, partially offset by $0.1 million of cash payments on terminated derivatives instruments compared to $17.6 million of cash received on expired derivative instruments and $0.8 million of cash received on terminated derivatives instruments for the year ended December 31, 2024. For the year ended December 31, 2025, we had a net gain on commodity derivative instruments of $28.4 million compared to a net loss of $2.0 million for the year ended December 31, 2024.

In addition, the Company paid $2.0 million pursuant to a settlement with PHMSA. See Note 17 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Investing Activities. Net cash provided by investing activities for the year ended December 31, 2025 was $141.3 million, of which $84.3 million was used for additions to oil and natural gas properties and $1.0 million was used for additions to other property and equipment. Net cash used in investing activities for the year ended December 31, 2024, was $82.0 million, of which $72.2 million was used for additions to oil and natural gas properties and $1.1 million used for additions to other property and equipment.

During 2025, the Company generated significant investing cash inflows from asset divestitures. These transactions included the sale of certain rights, title, and interests in East Texas assets for net proceeds of $13.6 million; the divestiture of non-operated working interests in the Eagle Ford for net proceeds of $23.0 million; the divestiture of all our East Texas/North Louisiana assets for net proceeds of $111.6 million; and the divestiture of all our Oklahoma assets for net proceeds of $88.7 million.

For the year ended December 31, 2024, in East Texas we sold some undeveloped acreage recognizing a gain of $1.4 million.

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with our offshore Beta properties. Additions to restricted investments were $10.2 million for the year ended December 31, 2025 compared to $10.1 million for the year ended December 31, 2024.

Financing Activities. We had net repayments under our Revolving Credit Facility of $127.0 million for the year ended December 31, 2025, compared to net borrowings of $12.0 million for the year ended December 31, 2024.

For the year ended December 31, 2024 compared to the year ended December 31, 2023

Information related to the comparison of our discussion of the cash flows for the year ended December 31, 2024 compared to the year ended December 31, 2023, is included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" of our 2024 Form 10-K filed with the SEC and is incorporated by reference into this Annual Report.

Capital Requirements

See "— Outlook" for additional information regarding our capital spending program for 2026.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm, begin on page F-1 of this Annual Report and are incorporated herein by reference.

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.

As required by Rules 13a-15(b) and 15d-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of the Company, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of the Company, as appropriate, to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon this evaluation the principal executive officer and principal financial officer of the Company have concluded that, because of the effect of the material weakness described below, our disclosure controls and procedures were not effective as of December 31, 2025.

Notwithstanding this material weakness, our management concluded that our consolidated financial statements included in Part II, Item 8 of this Annual Report on Form 10-K fairly present, in all material respects, our financial condition, results of operations and cash flows as of and for the periods presented in conformity with accounting principles generally accepted in the United States.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting, no matter how well designed, has inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Under the supervision and with the participation of the Company's management, including the principal executive officer and principal financial officer of the Company, the Company assessed the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this assessment, because of the effect of the material weakness described below, the Company's management concluded that the Company's internal control over financial reporting was not effective as of December 31, 2025, based on the criteria set forth under the COSO Framework.

A material weakness 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 our annual or interim financial statements will not be prevented or detected on a timely basis.

Management has concluded that the Company lacked the appropriate control processes and activities to sufficiently mitigate for changes in personnel with the necessary technical and accounting knowledge, experience, and training. This material weakness remains unremediated as of December 31, 2025.

The control deficiency has not resulted in a material error or misstatements to our financial statements or the need to revise any previously published financial results. However, the control deficiency could have resulted in a misstatement of one or more account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected, and accordingly, we determined that the control deficiency constitutes a material weakness.

Deloitte & Touche LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2025. The report, which expressed an adverse opinion as stated in the report, is contained herein under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Controls Over Financial Reporting

Other than the material weakness described above, there were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We are undertaking the remediation actions described below to remediate the material weakness that exists as of December 31, 2025.

The certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits 31.1 and 31.2 to this Annual Report.

Remediation Efforts to Address Material Weakness

Our management is committed to maintaining a strong internal control environment. In response to the identified material weakness above, management, with the oversight of the audit committee of the Board, is taking comprehensive actions to remediate the above material weakness. Our remediation plans include the following:

- Strengthening documentation for management's interpretation of technical accounting treatment; and
- Enhancing training and providing additional support for all participants in the accounting processes.

We may also conclude that additional measures may be required to remediate the material weakness in our internal control over financial reporting, which may necessitate additional implementation and evaluation time. We will continue to assess the effectiveness of our internal control over financial reporting and take steps to remediate the material weakness expeditiously. The material weakness will not be considered remediated until the applicable remediated controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Report of Independent Registered Public Accounting Firm

To the shareholders and the Board of Directors of Amplify Energy Corp.

Opinion on Internal Control Over Financial Reporting

We have audited the internal control over financial reporting of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, because of the effect of the material weakness identified below on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Company and our report dated March 9, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Material Weakness

A material weakness 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 the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment:

The Company lacked the appropriate control processes and activities to sufficiently mitigate for changes in personnel with the necessary technical and accounting knowledge, experience, and training.

This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2025, of the Company, and this report does not affect our report on such financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2026

ITEM 9B. OTHER INFORMATION

Rule 10b5-1 Trading Plans

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 INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement relating to the 2026 Annual Meeting of Stockholders of Amplify Energy Corp. (the "Proxy Statement") that is expected to be held in the second quarter of 2026.

The Company has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") which applies to employees, officers and directors of the Company. The Code of Ethics can be found on the Company's website located at https://www.amplifyenergy.com/investor-relations/corporate-governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) *Financial Statements*

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

(a)(2) *Financial Statement Schedules*

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

(a)(3) *Exhibits*

The exhibits listed on the Exhibit Index below are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

Exhibit Index

Exhibit Number	Description
2.1##	Agreement and Plan of Merger, dated January 14, 2025, by and among Amplify Energy Corp., Amplify DJ Operating LLC, Alpha PRB Operating LLC, North Peak Oil & Gas, LLC, Century Oil and Gas Sub-Holdings, LLC, Juniper Capital Advisors, L.P. and the Specified Company Entities signatories thereto (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-35512) filed on January 15, 2025).
2.2	Amendment No.1 to Agreement and Plan of Merger, dated as of April 14, 2025, by and among Amplify Energy Corp., Amplify Operating LLC, Amplify PRB Operating LLC, North Peak Oil & Gas, LLC, Century Oil and Gas Sub-Holdings, LLC, Juniper Capital Advisors, L.P. and the Specified Company Entities signatories thereto (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-35512) filed on April 15, 2025).
2.3##	Purchase and Sale Agreement, dated July 1, 2025, by and between Amplify Energy Operating LLC and Murphy Exploration & Production Company – USA (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on July 1, 2025).
2.4##	Purchase and Sale Agreement, dated October 28, 2025, among Amplify Energy Operating LLC, Magnify Energy Services LLC and EQV Alpha LLC (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on October 29, 2025).
2.5*	Closing Agreement and First Amendment to the Purchase and Sale Agreement, dated December 23, 2025, among Amplify Energy Operating LLC, Magnify Energy Services LLC and EQV Alpha LLC.
2.6##	Purchase and Sale Agreement, dated November 4, 2025, among Amplify Oklahoma Operating LLC, Magnify Energy Services LLC, Amplify Energy Operating LLC and Revolution Resources III, LLC (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on November 5, 2025).
3.1	Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	Certificate of Amendment to the Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc., dated August 6, 2019 (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).

Exhibit Number	Description
3.3	— Third Amended and Restated Bylaws of Amplify Energy Corp. (incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 15, 2021).
4.1	— Description of the Company's Capital Stock Registered Under Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (File No. 0001-35512) filed on March 5, 2020).
10.1	— Amended and Restated Credit Agreement dated July 31, 2023, among Amplify Energy Operating LLC, as borrower, Amplify Acquisitionco LLC, as parent, the lenders party thereto and KeyBank National Association, as administrative agent and a letter of credit issuer (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 1, 2023).
10.2	— Borrowing Base Redetermination, Commitment Increase and First Amendment to Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on October 25, 2024).
10.3	— Borrowing Base Redetermination, Commitment Increase and Second Amendment to Amended and Restated Credit Agreement, dated December 31, 2025 by and among Amplify Energy Operating LLC, Amplify Acquisitionco LLC, the guarantors party thereto, the lenders party thereto and Citizens Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on December 31, 2025).
10.4#	— Amplify Energy Corp. 2024 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-8 (File No. 333-279868) filed on May 31, 2024).
10.5#	— Form of 2024 TRSU Award Agreement (incorporated by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.6#	— Form of 2024 PRSU Award Agreement (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.7#	— Form of 2024 TRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.2 to the Company's Quarter Report on Form 10-Q (File No.001-33512) filed on August 7, 2024).
10.8#	— Form of 2024 PRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.3 to the Company's Quarter Report on Form 10-Q (File No.001-33512) filed on August 7, 2024).
10.9#	— Form of 2025 TRSU Award Agreement (incorporated by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K (File No.001-33512) filed on March 5, 2025).
10.10#	— Form of 2025 PRSU Award Agreement (incorporated by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K (File No.001-33512) filed on March 5, 2025).
10.11*#	— Form of 2026 TRSU Award Agreement.
10.12*#	— Form of 2026 PRSU Award Agreement.
10.13	— PRSU Award Agreement, dated as of July 22, 2025, by and between Daniel Furbee and Amplify Energy Corp. (incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on August 6, 2025).
10.14#	— Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and James Frew (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.15#	— Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Daniel Furbee (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.

Exhibit Number	Description
10.16#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Eric Willis (incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.17	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.16 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
10.18	Cooperation Agreement, dated as of May 16, 2025, by and among Amplify Energy Corp., Clint Coghill, Stoney Lonesome HF LP and The Drake Helix Holdings, LLC (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on May 19, 2025).
19.1	Insider Trading Policy and Other Restrictions on Trading (incorporated by reference to Exhibit 19.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
21.1*	List of Subsidiaries of Amplify Energy Corp.
23.1*	Consent of Cawley, Gillespie and Associates, Inc.
23.2*	Consent of Deloitte & Touche LLP.
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	Amplify Energy Corp. Clawback Policy (incorporated by reference to Exhibit 97.1 of the Company's Annual Report on Form 10-K (File No. 001-35512) filed on March 7, 2024).
99.1*	Report of Cawley, Gillespie and Associates, Inc.
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.DEF*	Inline XBRL Definition Linkbase Document
101.LAB*	Inline XBRL Labels Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed or furnished as an exhibit to this Annual Report on Form 10-K.

\# Management contract or compensatory plan or arrangement.

\## Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

ITEM 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Amplify Energy Corp.
(Registrant)

Date: March 9, 2026

By: /s/ James Frew
Name: James Frew
Title: President and Chief Financial Officer

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 their capacities and on the dates indicated.

Name	Title (Position with Amplify Energy Corp.)	Date
/s/ Dan Furbee Dan Furbee	Chief Executive Officer (Principal Executive Officer)	March 9, 2026
/s/ James Frew James Frew	President and Chief Financial Officer (Principal Financial Officer)	March 9, 2026
/s/ Natasha France Natasha France	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 9, 2026
/s/ Christopher W. Hamm Christopher W. Hamm	Chairman and Director	March 9, 2026
/s/ Deborah G. Adams Deborah G. Adams	Director	March 9, 2026
/s/ Clint Coghill Clint Coghill	Director	March 9, 2026
/s/ Todd R. Snyder Todd R. Snyder	Director	March 9, 2026

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AMPLIFY ENERGY CORP.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Amplify Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of operations, stockholders' equity, and cash flows, for each of the two years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also 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 (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 9, 2026, expressed an adverse opinion on the Company's internal control over financial reporting because of a material weakness.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Critical Audit Matter

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

Oil and Natural Gas Properties, Depletion – Oil and Natural Gas Reserve Quantities as used in the calculation of DD&A— Refer to Note 2 to the financial statements.

Critical Audit Matter Description

The Company's proved oil and natural gas properties are depleted using the units-of -production method based on proved oil and natural gas reserves related to the associated field. The development of the Company's oil and natural gas reserve quantities require management to make significant estimates and assumptions. The Company engages an independent reservoir engineer, management's specialist, to estimate oil and natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in assumptions or engineering data could have a significant impact on the amount of depletion expense.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's proved oil and natural gas reserves, including management's estimates and assumptions related to the best estimate of future production and converting proved undeveloped reserves to producing oil and natural gas properties within five years, required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas reserves included the following, among others:

- We tested the design and implementation and operating effectiveness of controls related to the Company's estimation of proved oil and natural gas reserve quantities.
- We evaluated the Company's best estimate of future production by:
    - Comparing the Company's best estimate of future production to historical production volumes.
    - Assessing the reasonableness of the production volume decline curves by comparing to historical decline curve estimates.
- We evaluated the reasonableness of management's estimates and assumptions related to converting proved undeveloped reserves to producing oil and natural gas properties within five years, by performing the following:
    - Comparing historical conversions of proved undeveloped reserves into proved developed reserves to management's forecasts of conversions.
    - Comparing management's forecasts to the Company's drilling plan and the availability of capital relative to the drilling plan.
    - Evaluating whether the forecasted date of development for the proved undeveloped locations are within five years of their original booking date.
    - Reviewing the internal development plan approved by management and the Board of Directors.
- •We evaluated the experience, qualifications and objectivity of management's expert, an independent reserve engineering firm.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2026

We have served as the Company's auditor since 2020.

AMPLIFY ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(In thousands, except outstanding shares)

	December 31, 2025	December 31, 2024
ASSETS		
Current assets:		
Cash and cash equivalents	$ 60,666	$ —
Accounts receivable, net (see Note 14)	30,141	39,713
Short-term derivative instruments	15,429	6,385
Prepaid expenses and other current assets	24,358	25,679
Total current assets	130,594	71,777
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	388,920	942,981
Support equipment and facilities	154,954	150,511
Other	9,601	11,478
Accumulated depreciation, depletion and amortization	(364,534)	(718,752)
Property and equipment, net	188,941	386,218
Long-term derivative instruments	3,425	233
Restricted investments	40,241	29,993
Operating lease - long term right-of-use asset	2,998	4,540
Deferred tax asset	233,334	251,600
Other long-term assets	1,367	2,715
Total assets	$ 600,900	$ 747,076
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 17,901	$ 13,231
Revenues payable	5,638	11,494
Accrued liabilities (see Note 14)	34,518	43,413
Total current liabilities	58,057	68,138
Long-term debt (see Note 9)	—	127,000
Asset retirement obligations	72,376	129,700
Operating lease liability	2,568	3,683
Other long-term liabilities	9,176	9,643
Total liabilities	142,177	338,164
Commitments and contingencies (see Note 17)		
Stockholders' equity (deficit):		
Preferred stock, $0.01 par value: 50,000,000 shares authorized; no shares issued and outstanding at December 31, 2025 and December 31, 2024	—	—
Warrants, warrants issued and outstanding at December 31, 2024	—	—
Common stock, $0.01 par value: 250,000,000 shares authorized; 40,719,957 and 39,795,138 shares issued and outstanding at December 31, 2025 and December 31, 2024, respectively	407	399
Additional paid-in capital	445,816	439,981
Accumulated deficit	12,500	(31,468)
Total stockholders' equity (deficit)	458,723	408,912
Total liabilities and equity	$ 600,900	$ 747,076

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Year Ended December 31,	
	2025	**2024**
Revenues:		
Oil and natural gas sales	$ 256,097	$ 282,992
Other revenues	7,264	11,689
Total revenues	263,361	294,681
Costs and expenses:		
Lease operating expense	141,324	142,950
Gathering, processing and transportation	17,795	18,427
Taxes other than income	15,870	20,895
Depreciation, depletion and amortization	32,484	32,586
Impairment expense	42,450	—
General and administrative expense	52,056	35,895
Accretion of asset retirement obligations	8,861	8,438
Loss (gain) on commodity derivative instruments	(28,397)	2,047
Pipeline incident loss	2,423	3,859
(Gain) loss on sale of properties	(99,548)	(1,367)
Other, net	1,103	531
Total costs and expenses	186,421	264,261
Operating income (loss)	76,940	30,420
Other income (expense):		
Interest expense, net	(15,577)	(14,599)
Other income (expense)	(524)	(447)
Total other income (expense)	(16,101)	(15,046)
Income (loss) before income taxes	60,839	15,374
Income tax (expense) benefit - current	1,377	(232)
Income tax (expense) benefit - deferred	(18,248)	(2,196)
Net income (loss)	43,968	12,946
Allocation of net income (loss) to:		
Net income (loss) available to common stockholders	41,601	12,324
Net income (loss) allocated to participating securities	2,367	622
Net income (loss) available to Amplify Energy Corp.	$ 43,968	$ 12,946
Earnings (loss) per share: (See Note 11)		
Basic and diluted earnings (loss) per share	$ 1.03	$ 0.31
Weighted average common shares outstanding:		
Basic and diluted	40,391	39,655

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31,	
	2025	2024
Cash flows from operating activities:		
Net income (loss)	$ 43,968	$ 12,946
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	32,484	32,586
Impairment expense	42,450	—
Loss (gain) on derivative instruments	(28,397)	2,047
Cash settlements (paid) received on expired derivative instruments	16,784	17,616
Cash settlements received (paid) on terminated derivative instruments	(93)	793
Deferred income tax expense (benefit)	18,248	2,196
Accretion of asset retirement obligations	8,861	8,438
(Gain) loss on sale of properties	(99,548)	—
Share-based compensation (see Note 12)	8,293	6,799
Settlement of asset retirement obligations	(1,274)	(1,170)
Amortization and write-off of deferred financing costs	2,676	1,233
Bad debt expense	1,188	80
Changes in operating assets and liabilities:		
Accounts receivable	8,120	(697)
Prepaid expenses and other assets	758	(7,561)
Payables and accrued liabilities	(5,523)	(24,013)
Other	205	—
Net cash provided by operating activities	49,200	51,293
Cash flows from investing activities:		
Additions to oil and gas properties	(84,334)	(72,226)
Additions to other property and equipment	(976)	(1,118)
Additions to restricted investments	(10,249)	(10,057)
Proceeds from the EQV Asset Sale	111,604	—
Proceeds from the Revolution Asset Sale	88,654	—
Proceeds from the sale of other oil and natural gas properties	36,599	1,367
Net cash provide by (used in) investing activities	141,298	(82,034)
Cash flows from financing activities:		
Advances on Revolving Credit Facility	126,000	117,000
Payments on Revolving Credit Facility	(253,000)	(105,000)
Deferred financing costs	(382)	(136)
Shares withheld for taxes	(2,450)	(1,869)
Net cash provide by (used in) financing activities	(129,832)	9,995
Net change in cash and cash equivalents	60,666	(20,746)
Cash and cash equivalents, beginning of period	—	20,746
Cash and cash equivalents, end of period	$ 60,666	$ —

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands)

	Stockholders' Equity			
	Common Stock	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
Balance at December 31, 2023	$ 393	$ 435,095	$ (44,452)	$ 391,036
Net income (loss)	—	—	12,946	12,946
Share-based compensation expense	—	6,761	38	6,799
Shares withheld for taxes	—	(1,869)	—	(1,869)
Other	6	(6)	—	—
Balance at December 31, 2024	399	439,981	(31,468)	408,912
Net income (loss)	—	—	43,968	43,968
Share-based compensation expense	—	8,293	—	8,293
Shares withheld for taxes	—	(2,450)	—	(2,450)
Other	8	(8)	—	—
Balance at December 31, 2025	$ 407	$ 445,816	$ 12,500	$ 458,723

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Basis of Presentation

General

Amplify Energy Corp. ("Amplify Energy," "Amplify," or the "Company"), is a publicly traded Delaware corporation, in which our common stock, par value of $0.01 per share ("Common Stock"), is listed on the New York Stock Exchange (the "NYSE"), under the symbol "AMPY."

The Company operates in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. The Company's management evaluates performance based on one reportable business segment as there are not different economic environments within the operation of our oil and natural gas properties.

The Company assets have historically consisted primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana and the Eagle Ford (non-op). The Company divested its assets in Oklahoma, East Texas/North Louisiana and the Eagle Ford (non-op) during the year ended December 31, 2025. See Note 4 for additional information related to the divestitures. The Company's oil and natural gas properties were located in large, mature oil and natural gas reservoirs. The Company's properties historically consisted primarily of operated and non-operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells.

As of the date of this 2025 Annual Report on Form 10-K, the Company properties consist of its Bairoil and Beta oil producing properties. The oil properties are located in mature oil reservoirs. As of December 31, 2025, we are the operator of record for properties containing 100% of our total estimated proved reserves.

Basis of Presentation

Material intercompany transactions and balances have been eliminated in preparation of the Company's Consolidated Financial Statements. The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

Amounts in the prior years consolidated financial statements are reclassified whenever necessary to conform to the current year's presentation. Reclassification adjustments had no impact on prior year net income (loss) or shareholders' equity.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of Consolidated 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 at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion and amortization of oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity compensation; and asset retirement obligations.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Beta oil and gas properties. These restricted investments consist of money market deposit accounts which are held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, individuals and others who own interests in the properties operated by the Company. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. The Company recorded $2.9 million and $1.7 million, respectively, as an allowance for doubtful accounts at December 31, 2025 and 2024.

If the Company was to lose any one of its customers, the loss could temporarily delay the production and the sale of oil and natural gas in the related producing region. If it were to lose any single customer, the Company believes that a substitute customer to purchase the impacted production volumes could be identified.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	For the Year Ended December 31,	
	2025	2024
Major customers:		
Phillips 66	28 %	33 %
HF Sinclair Corporation (formerly: Sinclair Oil & Gas Company)	21 %	25 %
Southwest Energy LP	n/a %	10 %

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. The costs of exploratory wells are initially capitalized, pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, seismic costs and delay rental payments attributable to unproved locations are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

Support equipment and facilities, which are primarily related to our Bairoil and Beta assets, are depreciated using the straight-line method generally based on estimated useful lives of twelve to twenty-four years.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2025 and 2024.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the Consolidated Financial Statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board ("FASB"). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. The development of the Company's oil and natural gas reserve quantities requires management to make significant estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within a five-year development period, as prescribed by SEC guidelines. Additionally, none of the Company's PUDs are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUD as prescribed by the SEC guidelines. PUDs are converted from undeveloped to developed as applicable wells begin production. We engaged Cawley, Gillespie and Associates, Inc. ("CG&A"), our independent reserve engineers, to prepare our reserves estimates for all of the Company's estimated proved reserves at December 31, 2025 and 2024.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment are stated at historical cost and is comprised primarily of vehicles, furniture, fixtures, office build-out cost and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to seven years.

Restricted Investments

Restricted investment accounts fund certain long-term asset retirement obligations and collateralize certain regulatory bonds associated with the Beta oil and gas properties. These investments are classified as held-to-maturity and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense, net in the Consolidated Statements of Operations. These restricted investments may consist of money market deposit accounts and U.S. Government securities. See Note 8 and Note 17 for additional information.

Debt Issuance Costs

Debt issuance costs are recorded in other long-term assets line item on the balance sheet and amortized over the term of the associated debt using the straight-line method, which generally approximates the effective yield method. Amortization expense, including write-off of debt issuance costs, for the years ended December 31, 2025 and 2024 was approximately $2.7 million and $1.2 million, respectively, as reflected in interest expense, net in the Consolidated Statements of Operations.

Impairments

Oil and natural gas properties including supporting equipment and facilities are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. This may be due to a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future net cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted net future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of future proved and probable reserves, commodity prices, production costs, and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

During the year, the Company recorded impairment charges related to certain oil and natural gas properties that were identified for sale in connection with our divestiture activities. In accordance with ASC 360, the Company evaluated these assets for recoverability once management committed to a plan to sell them. Based on this evaluation, the Company determined that the carrying amounts of the assets were not recoverable and exceeded their estimated fair values. Fair value was estimated using a discounted cash flow model that incorporated management's best estimates of the expected sales prices, timing of disposal, and other market-based assumptions available at the time of the assessment. The expected sales prices represented the primary input to the fair value determination, as they reflected the amounts the Company reasonably anticipated to receive in an orderly transaction between market participants.

As a result of this analysis, the Company recognized impairment charges to reduce the carrying values of the assets to their estimated fair values less costs to sell. The assets subject to impairment were subsequently sold during the year, and the recognized impairment charges aligned the carrying values with the expected economic outcomes of the sales. The Company recorded an impairment expense of $42.5 million for the year ended December 31, 2025. No impairment expense was recorded for the year ended December 31, 2024.

Unproved oil and natural gas properties are reviewed for impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, the expense is reported in impairment expense. No impairment expense related to the Company's unproved properties was recorded for the years ended December 31, 2025 and 2024.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized in net income (loss) to the extent the actual costs differ from the recorded liability. See Note 7 for further discussion of asset retirement obligations.

Revenue Recognition

The Company revenue is primarily derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from natural gas during processing. Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. The performance obligation is the delivery of the commodity at a point in time. Prices for oil, natural gas and NGLs sales are negotiated based on index or spot price, distance from the well to pipeline, commodity quality and prevailing supply and demand conditions. To the extent actual quantities and values of oil, NGLs and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties must be estimated.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars and puts) are used to reduce the impact of natural gas and oil price fluctuations. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

The Company is a corporation subject to federal and certain state income taxes.

The Company uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled.

In assessing the carrying value of the Company's net deferred tax assets, it considers the realizability of its deferred tax assets each reporting period. The realization of any deferred tax asset is dependent upon the generation of future taxable income sufficient to demonstrate its ability to utilize the deferred tax asset in the period in which the temporary differences become deductible or in a future period prior to expiration. The Company considers all available evidence, including cumulative historical losses (defined as pre-tax earnings as adjusted for permanent tax adjustment), scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies.

The Company recognizes a tax (expense) benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination by taxing authorities, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through effective settlement with a taxing authority. As of December 31, 2025, the Company has no uncertain tax positions.

Earnings (loss) Per Share

Basic and diluted earnings (loss) per share ("EPS") is determined by dividing net income (loss) available to the common stockholders by the weighted average number of outstanding shares during the period. Diluted earnings (loss) per common share is calculated under the two-class method and the treasury stock method by dividing net income (loss) available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 11 for additional information.

Equity Compensation

The fair value of equity-classified awards (e.g., restricted common unit awards, restricted stock units or stock options) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., phantom units awards) are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. The Company currently has awards subject to performance criteria; such awards would vest when it is probable that the performance criteria will be met and the requisite service period has been met. Generally, no compensation expense is recognized for equity instruments that do not vest. See Note 12 for further information.

Lease Recognition

The FASB retained a dual model, requiring leases to be classified as either direct financing or operating leases. The classification will be based on criteria that are similar to the current lease accounting treatment. The Company is the lessee under various agreements for office space, warehouse, compressors, equipment, vehicles and surface rentals (right of use assets) that are currently accounted for as operating leases. See Note 13 for additional information regarding leases.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Loss of Production Income Insurance

The Company's insurance coverage includes loss of production income ("LOPI") insurance for our offshore properties. Proceeds from LOPI insurance claims are intended to partially offset the loss of revenue resulting from certain events that cause suspension of operations. When such event occurs, the Company files claims under its LOPI policy and recognizes LOPI in the period that insurers accept the claim and all uncertainty with respect to the receipt or amount of claim is resolved. The Company classifies LOPI within "Other revenues" in the Consolidated Statements of Operations.

Insurance Coverage

The Company recognizes an insurance receivable when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between the insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment.

New Accounting Pronouncements

Income Statement –Expense Disaggregation Disclosures. In November 2024, the FASB issued an accounting standard update which requires disaggregated disclosures of income statement expenses for public business entities. The guidance will require companies to disclose disaggregated information about specific natural expense categories underlying certain income statement expense line items that are considered relevant because they include one or more of the five natural expense categories, as applicable: (1) purchase of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, and (5) depreciation, depletion and amortization ("DD&A") recognized as part of oil and gas producing activities or other depletion expenses. The new guidance is effective for annual periods beginning after December 15, 2026 and interim periods within fiscal years beginning after December 31, 2027. The Company is currently evaluating the impact of this guidance on the Company's financial disclosures. Adoption of the update will not impact the Company's financial position, results of operations or liquidity.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

Note 3. Revenues

Revenue from contracts with customers

Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as gathering, processing and transportation and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Disaggregation of Revenue

The Company has identified three material revenue streams in its business: oil, natural gas and NGLs. The following table presents the Company's revenues disaggregated by revenue stream.

	For the Year Ended December 31,	
	2025	2024
	(in thousands)	
Revenues		
Oil	$ 182,764	$ 220,380
NGLs	21,379	26,789
Natural gas	51,954	35,823
Oil and natural gas sales	$ 256,097	$ 282,992

Contract Balances

Under its sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, its contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to the Company's revenue contracts with customers were $23.0 million and $28.5 million at December 31, 2025 and 2024, respectively.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's contracts that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's contracts, each unit of product delivered to the customer 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. For the Company's contracts that have a contract term of one year or less, the Company has utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Note 4. Acquisitions and Divestitures

2025 Divestitures

Revolution Purchase and Sale Agreement

On November 4, 2025, Amplify Oklahoma Operating LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Amplify Oklahoma"), Magnify (together with Amplify Oklahoma, the "Revolution Sellers") and OLLC, for certain limited purposes, entered into a purchase and sale agreement (the "Revolution Purchase and Sale Agreement") with Revolution Resources III, LLC, a Delaware limited liability company ("Revolution"), pursuant to which the Revolution Sellers sold to Revolution certain assets of the Revolution Sellers, which include, among other things, the Revolution Sellers' right, title and interest in and to certain specified oil and gas properties and equipment within or related to certain designated lands in Oklahoma (the "Revolution Asset Sale") for a cash purchase price of $92.5 million, subject to estimated post-closing adjustments under the Revolution Purchase and Sale Agreement. The Revolution Asset Sale closed on December 29, 2025, with an effective date of October 1, 2025. For the year ended December 31, 2025, the Company recorded a loss of $2.3 million in "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations. The Company recognized an impairment expense of approximately $34.0 million for the year ended December 31, 2025 in connection with the divestiture. The proceeds from the Revolution Asset Sale were used to reduce borrowings under our Revolving Credit Facility. Upon the asset sale, the Company no longer holds any assets in Oklahoma. This disposition did not qualify as discontinued operation.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

EQV Purchase and Sale Agreement

On October 28, 2025, OLLC and Magnify Energy Services LLC, a Delaware limited liability company and indirect, wholly owned subsidiary of the Company ("Magnify" and together with OLLC, the "EQV Sellers"), entered into a purchase and sale agreement (the "EQV Purchase and Sale Agreement") with EQV Alpha LLC, a Delaware limited liability company ("Alpha"), pursuant to which the EQV Sellers sold to Alpha certain assets of the EQV Sellers, which include, among other things, the EQV Sellers' right, title and interest in and to certain specified oil and gas Properties and Equipment (each as defined in the EQV Purchase and Sale Agreement) within or related to certain designated lands in East Texas and Louisiana (the "EQV Asset Sale") for a cash purchase price of $122.0 million, subject to estimated post-closing adjustments under the EQV Purchase and Sale Agreement. The EQV Asset Sale closed on December 23, 2025, with an effective date of October 1, 2025. For the year ended December 31, 2025, the Company recorded a gain of $87.1 million in "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations. The proceeds from the EQV Asset Sale were used to reduce borrowings under our Revolving Credit Facility. Upon the asset sale, the Company no longer holds any assets in East Texas/North Louisiana. This disposition did not qualify as discontinued operation.

Sale of Non-Operated Eagle Ford Assets

On July 1, 2025, OLLC entered into a definitive agreement (the "Purchase and Sale Agreement") with Murphy Exploration & Production Company – USA, a Delaware corporation ("Buyer"), the existing operator of the majority of OLLC's Assets (as defined in the Purchase and Sale Agreement), pursuant to which OLLC sold to Buyer all of OLLC's Assets, which include, among other things, OLLC's right, title and interest in and to certain specified oil and gas Properties, Contracts, Equipment and Production (each, as defined in the Purchase and Sale Agreement) within or related to certain designated lands in Karnes County, Texas, for an aggregate cash purchase price of $23.0 million, excluding $1.9 million final post-closing adjustments, resulting in a final adjusted purchase price of $21.1 million (the " Eagle Ford Asset Sale"). The Eagle Ford Asset Sale closed simultaneously with the execution and delivery of the Purchase and Sale Agreement on July 1, 2025. The Purchase and Sale Agreement became effective as of June 15, 2025. For the year ended December 31, 2025, the Company recorded a gain of $1.2 million in "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations. The Company recognized an impairment expense of approximately $8.4 million for the year ended December 31, 2025 in connection with the divestiture. Upon the asset sale, the Company no longer holds any assets in the Eagle Ford. This disposition did not qualify as discontinued operation.

East Texas Haynesville Monetization

On January 15, 2025, the Company sold 90% of its interest in certain units with rights in the Cotton Valley and Haynesville basins in Harrison County, Texas and purchased a 10% interest in adjacent acreage, generating $6.3 million in net proceeds from the transactions. These transactions also established an area of mutual interest with the counterparty covering 10,000 gross acres. The Company retained a 10% working interest in the units it divested and purchased a 10% working interest in the counterparty's acreage. The net proceeds received from the purchase and sale transactions of $6.3 million, which is classified as a gain in the "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations.

On May 1, 2025, the Company sold 90% of its interest in three units with rights in the Haynesville basin in Panola and Shelby Counties, Texas to a third party. Amplify retained a 10% working interest in the units it divested. The net proceeds from the transaction of $1.5 million which is classified as a gain in the "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations.

On October 2, 2025, the Company entered into a purchase and sale agreement to sell its remaining interest in certain units with rights in the Cotton Valley and Haynesville basins in Harrison County, Texas, generating $5.3 million in net proceeds from the transaction, which is classified as a gain in the "(gain) loss on sale of properties" in the Company's Consolidated Statement of Operations. The sale closed on October 24, 2025 and had an effective date of October 1, 2025.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Contemplated Merger with Juniper Capital

On January 14, 2025, the Company entered into an Agreement and Plan of Merger, as subsequently amended (the "Merger Agreement") with Amplify DJ Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of the Company ("First Merger Sub"), Amplify PRB Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of Amplify Energy ("Second Merger Sub"), North Peak Oil & Gas, LLC, a Delaware limited liability company ("NPOG"), Century Oil and Gas Sub-Holdings, LLC, a Delaware limited liability company ("COG" and, together with NPOG, the "Acquired Companies"), and, solely for the limited purposes set forth in the Merger Agreement, Juniper Capital Advisors, L.P. ("Juniper Capital") and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the effective time of the Contemplated Mergers (as defined below), it was contemplated that (i) NPOG would merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (ii) COG would merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement (clauses (i) and (ii), together, the "Contemplated Mergers").

On April 25, 2025, pursuant to Section 8.1(a) of the Merger Agreement, the Company and the Acquired Companies entered into a mutual termination agreement (the "Termination Agreement") to terminate the Merger Agreement (the "Termination"), effective immediately. As a result of the Termination Agreement, the Merger Agreement is of no further force and effect.

2024 Divestitures

During the year ended December 31, 2024, the Company sold certain rights, title and interest in assets located in East Texas to a third party. The Company recorded a gain of approximately $1.4 million, as reflected in the "(gain) loss on sale of properties" in the Consolidated Statements of Operations.

Acquisition and Divesture Expenses

Acquisition and divestiture related expenses for third-party transactions are included in general and administrative expense in the Consolidated Statements of Operations for the periods indicated below (in thousands):

	For the Year Ended December 31,	
	2025	2024
Cost incurred related to the contemplated merger with Juniper Capital	$ 2,769	$ 1,383
Cost incurred related to the EQV Asset Sale and the Revolution Asset Sale	5,399	—
Other acquisition and divestitures expenses	1,722	250
	$ 9,890	$ 1,633

Note 5. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 — Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is one in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Level 2 — Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. At December 31, 2025 and 2024, all of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

Level 3 — Measure based on prices or valuation models that require inputs that are both significant to the fair value measurement and are less observable from objective sources (i.e., supported by little or no market activity).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The carrying values of cash and cash equivalents (Level 1), accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at December 31, 2025 and 2024. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables. See Note 9 for the estimated fair value of our outstanding fixed-rate debt.

The fair market values of the derivative financial instruments reflected on the balance sheets as of December 31, 2025 and 2024 were based on estimated forward commodity prices (including nonperformance risk). Nonperformance risk is the risk that the obligation related to the derivative instrument will not be fulfilled. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table presents the derivative assets and liabilities that are measured at fair value on a recurring basis at December 31, 2025 and 2024 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2025			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$ —	$ 18,854	$ —	$ 18,854
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 18,854	$ —	$ 18,854
Liabilities:				
Commodity derivatives	$ —	$ —	$ —	$ —
Interest rate derivatives	—	—	—	—
Total liabilities	$ —	$ —	$ —	$ —

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Fair Value Measurements at December 31, 2024			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
		(In thousands)		
Assets:				
Commodity derivatives	$ —	$ 14,317	$ —	$ 14,317
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 14,317	$ —	$ 14,317
Liabilities:				
Commodity derivatives	$ —	$ 7,699	$ —	$ 7,699
Interest rate derivatives	—	—	—	—
Total liabilities	$ —	$ 7,699	$ —	$ 7,699

See Note 6 for additional information regarding our derivative instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis, as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

- The fair value of asset retirement obligations ("AROs") is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. The initial fair value estimates are based on unobservable market data and are classified within Level 3 of the fair value hierarchy. See Note 7 for a summary of changes in AROs.

- If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital. The fair value of supporting equipment, such as plant assets, acquired in transactions accounted for as business combinations is commonly estimated using the depreciated replacement cost approach.

- Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. The Company uses an income approach based on the discounted cash flow method, whereby the present value of expected future net cash flows are discounted by applying an appropriate discount rate, for purposes of placing a fair value on the assets. The future cash flows are based on management's estimates for the future. The unobservable inputs used to determine fair value include, but are not limited to, estimates of proved reserves, estimates of probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties (some of which are Level 3 inputs within the fair value hierarchy).

  (i) During the year, the Company recorded impairment charges related to certain oil and natural gas properties that were identified for sale in connection with our divestiture activities. As a result of this analysis, the Company recognized impairment charges to reduce the carrying values of the assets to their estimated fair values less costs to sell. The assets subject to impairment were subsequently sold during the year, and the recognized impairment charges aligned the carrying values with the expected economic outcomes of the sales. The Company recorded an impairment expense of $42.5 million for the year ended December 31, 2025.

  (ii) No impairment expense on our proved oil and natural gas properties or support equipment was recorded for the year ended December 31, 2024.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price fluctuations and achieve a more predictable cash flow in connection with oil and natural gas sales from production. These transactions limit exposure to declines in prices but also limit the benefits that would be realized if prices increase.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our previous and current credit agreement are counterparties to our derivative contracts. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. The Company enters into International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of its counterparties. The terms of the ISDA Agreements provide the Company and each of its counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or its counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. See Note 9 for additional information regarding the Company's Revolving Credit Facility.

Commodity Derivatives

A combination of commodity derivatives (e.g., floating-for-fixed swaps, put options, costless collars, and three-way collars) is used to manage exposure to commodity price volatility.

The Company enters into natural gas derivative contracts that are indexed to NYMEX Henry-Hub. The Company also enters into oil derivative contracts indexed to either NYMEX WTI or Inter-Continental Exchange ("ICE") Brent. Its NGL derivative contracts are indexed to Oil Price Information Service Mont Belvieu.

In connection with the EQV Asset Sale as discussed in Note 4, the Company novated certain commodity derivative contracts to EQV Sellers pursuant to the EQV Purchase and Sale Agreement, which reduced the Company's commodity derivative portfolio at December 31, 2025. The novated derivative contracts were recorded at fair value at the time of novation, and their value was reflected as an adjustment to the purchase price through the preliminary closing settlement statement.

Upon novation, the Company derecognized the derivative contracts from the consolidated balance sheets. The fair value of the novated derivatives was included in the loss (gain) on commodity derivative instruments recorded in the Company's Consolidated Statements of Operations for the year ended December 31, 2025.

At December 31, 2025, the Company had the following open commodity positions:

	2026	2027
Crude Oil Derivative Contracts:		
Fixed price swap contracts:		
Average monthly volume (Bbls)	152,500	57,417
Weighted-average fixed price	$ 65.63	$ 62.53

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheet Presentation

The following table summarizes both: (i) the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the balance sheet and (ii) the net recorded fair value as reflected on the balance sheet at December 31, 2025 and 2024. There was no cash collateral received or pledged associated with its derivative instruments since all of the counterparties, or certain of their affiliates, to its derivative contracts are lenders under the Company's Credit Agreement (as defined below).

Type	Balance Sheet Location	Asset Derivatives December 31, 2025	Liability Derivatives December 31, 2025	Asset Derivatives December 31, 2024	Liability Derivatives December 31, 2024
			(In thousands)		
Commodity contracts	Short-term derivative instruments	$ 15,429	$ —	$ 9,499	$ 3,114
Interest rate swaps	Short-term derivative instruments	—	—	—	—
Gross fair value		15,429	—	9,499	3,114
Netting arrangements		—	—	(3,114)	(3,114)
Net recorded fair value	Short-term derivative instruments	$ 15,429	$ —	$ 6,385	$ —
Commodity contracts	Long-term derivative instruments	$ 3,425	$ —	$ 4,818	$ 4,585
Interest rate swaps	Long-term derivative instruments	—	—	—	—
Gross fair value		3,425	—	4,818	4,585
Netting arrangements		—	—	(4,585)	(4,585)
Net recorded fair value	Long-term derivative instruments	$ 3,425	$ —	$ 233	$ —

(Gains) Losses on Derivatives

The Company does not designate derivative instruments as hedging instruments for accounting and financial reporting purposes. Accordingly, all gains and losses, including changes in the derivative instruments' fair values, have been recorded in the accompanying statements of operations. The following table details the gains and losses related to derivative instruments for the periods indicated (in thousands):

	Statements of Operations Location	For the Year Ended December 31, 2025	2024
Commodity derivative contracts	Loss (gain) on commodity derivatives	$ (28,397)	$ 2,047

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the Company's portion of future plugging and abandonment of wells and related facilities. The following table presents the changes in the asset retirement obligations for the years ended December 31, 2025 and 2024 (in thousands):

	For the Year Ended December 31,	
	2025	2024
Asset retirement obligations at beginning of period	$ 131,077	$ 123,494
Liabilities added from acquisition or drilling	10	1
Liabilities settled	(1,274)	(1,170)
Liabilities removed upon sale of wells	(66,277)	—
Accretion expense	8,861	8,438
Revision of estimates	279	314
Asset retirement obligation at end of period	72,676	131,077
Less: Current portion	300	1,377
Asset retirement obligations - long-term portion	$ 72,376	$ 129,700

Note 8. Restricted Investments

Various restricted investment accounts fund certain long-term contractual and asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Beta oil and gas properties. The components of the restricted investment balances are as follows:

	December 31,	
	2025	2024
	(In thousands)	
BOEM platform abandonment (See Note 17)	$ 35,603	$ 25,448
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment	4,638	4,545
Restricted investments	$ 40,241	$ 29,993

Note 9. Long-Term Debt

The Company's consolidated debt obligations consisted of the following at the dates indicated:

	December 31, 2025	December 31, 2024
	(In thousands)	
Revolving Credit Facility [1]	$ —	$ 127,000
Total long-term debt	$ —	$ 127,000

(1) The carrying amount of the Company's Revolving Credit Facility approximates fair value because the interest rates are variable and reflective of market rates.

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Amended and Restated Credit Agreement

On July 31, 2023, Amplify Energy Operating LLC ("OLLC"), a wholly owned subsidiary of the Company and Amplify Acquisitionco LLC ("Acquisitionco"), as the direct parent of OLLC and wholly owned subsidiary of the Company, entered into the Amended and Restated Credit Agreement (the "Credit Agreement"), providing for a senior secured reserve-based revolving credit facility (the "Revolving Credit Facility"). The Revolving Credit Facility is guaranteed by the Company and all of its material subsidiaries and secured by substantially all of its assets. The Revolving Credit Facility was originally set to mature on July 31, 2027, and is a replacement in full of the prior Revolving Credit Facility, by and among OLLC, Acquisitionco, the guarantors party thereto, the lenders party thereto and KeyBank National Association, as administrative agent.

On October 25, 2024, OLLC entered into the first amendment to the Revolving Credit Facility, which, among other things, (i) reduced the borrowing base under the Revolving Credit Facility from $150.0 million to $145.0 million, (ii) increased the aggregate elected commitments under the Revolving Credit Facility from $135.0 million to $145.0 million and (iii) amended certain interest rates applicable to loans under the Revolving Credit Facility.

On December 31, 2025, OLLC entered into the Borrowing Base Redetermination, Commitment Increase and Second Amendment to the Credit Agreement (the "Second Amendment"), among OLLC, Amplify Acquisitionco LLC, the guarantors party thereto, the lenders party thereto and Citizens Bank, N.A., as administrative agent for the lenders. The Second Amendment amends the Credit Agreement, among other things: (i) set the Borrowing Base to $25.0 million, with elected commitments of $15.0 million and (ii) extend the maturity date under the Credit Agreement to December 31, 2028.

Certain key terms and conditions under the Revolving Credit Facility, as amended, include (but are not limited to):

- A maturity date of December 31, 2028;
- The loans shall bear interest at a rate per annum equal to (i) adjusted SOFR or (ii) an adjusted base rate, plus an applicable margin based on a utilization ratio of the lesser of the borrowing base and the aggregate commitments. The applicable margin ranges from 2.00% to 3.00% for adjusted base rate borrowings, and 3.00% to 4.00% for adjusted SOFR borrowings;
- The unused commitments under the facility will accrue a commitment fee of 0.50%, payable quarterly in arrears;
- Certain financial covenants, including the maintenance of (i) a net debt leverage ratio not to exceed 3.00 to 1.00, determined as of the last day of each fiscal quarter for the four fiscal-quarter period then ending, commencing on the fiscal quarter ending March 31, 2026 and (ii) a current ratio of not less than 1.00 to 1.00, determined as of the last day of each fiscal quarter, commencing with the fiscal quarter ending December 31, 2023;
- Certain events of default, including, without limitation: non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy; and
- Minimum hedging requirements ranging from 25%-75%, depending on availability under the Revolving Credit Facility, of the reasonably projected monthly production of hydrocarbons from proved developed producing reserves for the 12-month period immediately following the date of determination.

The Company had no loans outstanding under the Revolving Credit Facility as of December 31, 2025. The borrowing base under the facility is $25.0 million with elected commitments of $15.0 million at December 31, 2025. The Revolving Credit Facility borrowing base will be redetermined on a semi-annual basis based on an engineering report with respect to the Company's estimated oil and NGL reserves, which will take into account the prevailing oil and NGL prices at such time, as adjusted for the impact of commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt Compliance

As of December 31, 2025, the Company was in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with the Company's Revolving Credit Facility.

Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on variable-rate debt obligations for the periods presented:

	For the Year Ended December 31,	
	2025	2024
Revolving Credit Facility	8.39 %	9.27 %

Letters of credit

At December 31, 2025, the Company had no letters of credit outstanding.

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with the Revolving Credit Facility was $1.0 million at December 31, 2025. The unamortized deferred financing costs are amortized over the remaining life of the Revolving Credit Facility using the straight-line method, which generally approximates the effective interest method.

For the year ended December 31, 2025, the Company wrote off $1.5 million of deferred financing cost.

Note 10. Equity (Deficit)

Equity Outstanding

The Company's authorized capital stock includes 250,000,000 shares of common stock, $0.01 par value per share. The following table summarizes the changes in the number of outstanding common units and shares of common stock:

	Common Stock
Balance, December 31, 2023	39,147,205
Issuance of common stock	—
Restricted stock units vested	911,536
Shares withheld for taxes (1)	(263,603)
Balance, December 31, 2024	39,795,138
Issuance of Common Stock	—
Restricted stock units vested	1,392,938
Shares withheld for taxes (1)	(468,119)
Balance, December 31, 2025	40,719,957

(1) Represents the net settlement on vesting of restricted stock to satisfy the tax withholding requirements.

AMPLIFY ENERGY CORP.
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Note 11. Earnings (Loss) per Share

The following sets forth the calculation of earnings (loss) per share, or EPS, for the periods indicated (in thousands, except per share amounts):

	For the Year Ended December 31,	
	2025	2024
Net income (loss)	$ 43,968	$ 12,946
Less: Net income allocated to participating securities	2,367	622
Basic and diluted earnings available to common stockholders	$ 41,601	$ 12,324
Common shares:		
Common shares outstanding — basic	40,391	39,655
Dilutive effect of potential common shares	—	—
Common shares outstanding — diluted	40,391	39,655
Net earnings (loss) per share:		
Basic	$ 1.03	$ 0.31
Diluted [1]	$ 1.03	$ 0.31

(1) The Company excluded 525,587 and 817,098 restricted stock units from the diluted weighted-average common shares outstanding for the year ended December 31, 2025 and 2024, respectively, because their effect was anti-dilutive.

Note 12. Equity-based Awards

In May 2021, the Company shareholders approved an Equity Incentive Plan ("2021 EIP") in which the Legacy Amplify Management Incentive Plan (the "Legacy Amplify MIP") and the Legacy Amplify 2017 Non-Employee Directors Compensation Plan (the "Legacy Amplify Non-Employee Directors Compensation Plan") were replaced by the 2021 EIP and no further awards will be granted under the Legacy Amplify MIP or the Legacy Amplify Non-Employee Directors Compensation Plan.

On May 15, 2024, the Company's shareholders approved the Amplify Energy Corp. 2024 Equity Incentive Plan (the "2024 EIP" and together with the 2021 EIP, the "EIP Plans"), which had previously been approved by the board of directors of the Company (the "Board"). No further awards will be granted under the prior 2021 EIP.

The 2024 EIP Plan provides for awards that can be granted in the form of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance awards, stock awards and other incentive awards. To the extent that an award granted under either of the EIP Plans is canceled, expired, forfeited, settled in cash or otherwise terminated without delivery of shares of common stock, the shares of Common Stock retained by or returned to the Company will be available for future awards under the 2024 EIP. Any shares that are tendered by a participant or withheld by the Company (i) in payment of the exercise, base or purchase price relating to a stock option or stock appreciation right under either of the EIP Plans, or (ii) to satisfy any taxes or tax withholding obligations with respect to a stock option or stock appreciation right under either of the EIP Plans, as applicable, will not be available for future awards under the 2024 EIP. Any shares that are withheld by the Company or tendered by a participant to satisfy tax withholding obligations associated with any award other than stock options or stock appreciation rights granted under the 2024 EIP will become available again for future awards under the 2024 EIP. The 2024 EIP is administered by the Board. At December 31, 2025, the Company had 626,673 shares remaining available for issuance under the 2024 EIP.

Restricted Stock Units

Restricted Stock Units with Service Vesting Condition

Restricted stock units with service vesting conditions ("TSUs") are accounted for as equity-classified awards or liability-classified awards. The grant-date fair value is recognized as compensation cost on a straight-line basis over the requisite service period and forfeitures are accounted for as they occur. The Company considered its intent and ability to settle awards in cash or shares of stock in determining whether to classify the awards as equity or liability awards. Compensation costs for equity-classified awards are recorded as general and administrative expense. The fair value of liability-classified awards is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general administrative expense and are remeasured at fair value each reporting period.

In February 2024, the Company granted contingent cash-settlement awards in the form of TSUs (the "2024 TSUs"). In May 2024, the Company received shareholder approval of the 2024 EIP, which nullified the contingent cash settlement component for the 2024 TSUs. As of June 30, 2024, the 2024 TSUs were reclassified as equity awards. The compensation cost related to these awards is determined by the fair value of the award on the modification date. The 2024 TSUs will vest in substantially equal installments over a three-year period.

The unrecognized cost associated with TSUs was $4.1 million at December 31, 2025. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of 1.6 years.

The following table summarizes information regarding the TSUs granted under the EIP Plans for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
TSUs outstanding at December 31, 2023	1,331,456	$ 5.77
Granted (2)	858,314	$ 6.37
Forfeited	(5,922)	$ 5.04
Vested	(804,492)	$ 5.29
TSUs outstanding at December 31, 2024	1,379,356	$ 6.43
Granted (3)	983,549	$ 4.99
Forfeited	(2,533)	$ 5.34
Vested	(1,107,447)	$ 6.06
TSUs outstanding at December 31, 2025	1,252,925	$ 5.63

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2024 was $5.5 million based on a grant date market price ranging from $6.26 to $6.72 per share.
(3) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2025 was $4.9 million based on a grant date market price ranging from $3.28 to $5.34 per share.

Restricted Stock Units with Market and Service Vesting Conditions

Restricted stock units with market and service vesting conditions ("PSUs") are accounted for as equity-classified awards or liability-classified awards. The grant-date fair value is recognized as compensation cost on a graded-vesting basis. The fair value of the awards is estimated on their grant dates using a Monte Carlo simulation.

The Company recognizes compensation cost over the requisite service or performance period. The Company accounts for forfeitures as they occur. Compensation costs are recorded as general and administrative expense. The unrecognized cost associated with these awards was $1.9 million at December 31, 2025. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of approximately 1.7 years.

2023 PSU Awards

The 2023 PSU awards are accounted for as equity-classified awards and were issued with a three-year vesting period beginning on the grant date and ending on the third anniversary of the grant date. The three-year performance period for the 2023 awards is January 1, 2023 through December 31, 2025. Vesting of PSUs can range from zero to 200% of the target units granted based on the Company's relative total shareholder return as compared to the total shareholder return of the Company's performance peer group over the applicable performance period.

2024 PSU Award

In February 2024, the Company granted contingent cash-settlement awards in the form of PSUs (the "2024 PSUs"). In May 2024, the Company received shareholder approval of the 2024 EIP, which nullified the contingent cash settlement component for the 2024 PSUs. As of June 30, 2024, the 2024 PSUs were reclassified as equity awards with a three-year vesting period. The compensation cost related to these awards is determined by the fair value of the award on the modification date. The three-year performance period for the 2024 PSUs is January 1, 2024 through December 31, 2026.

2025 PSU Awards

The 2025 PSU awards are accounted for as equity-classified awards and were issued with a three-year vesting period beginning on the grant date and ending on the third anniversary of the grant date. The three-year performance period for the 2025 awards is January 1, 2025 through December 31, 2027. Vesting of PRSUs can range from zero to 200% of the target units granted based on the Company's relative total shareholder return as compared to the total shareholder return of the Company's performance peer group over the applicable performance period.

In connection with Mr. Daniel Furbee's appointment as Chief Executive Officer, he received a grant of 100,000 PSUs (the "Target PSUs") on July 22, 2025. The Target PSUs are subject to a performance period that began on July 22, 2025 and ends on March 31, 2028 (the "Performance Period"). The Target PSUs will vest, subject to Mr. Furbee's continued employment through the settlement date, as follows: (i) 50% of the Target PSUs will vest if the 20-day volume-weighted average closing price ("VWAP") of a share of Company common stock for the 20 consecutive trading days immediately preceding the end of the Performance Period equals at least $6.00 but less than $8.00, (ii) 100% of the Target PSUs will vest if the 20-day VWAP of a share of Company common stock for the 20 consecutive trading days immediately preceding the end of the Performance Period equals at least $8.00, but less than $10.00, and (iii) 200% of the Target PSUs will vest if the 20-day VWAP of a share of the Company's common stock for the 20 consecutive trading days immediately preceding the end of the Performance Period equals at least $10.00, with linear interpolation to apply for actual performance achieved between the foregoing thresholds.

The below table reflects the ranges for the assumptions used in the Monte Carlo model for the 2025 and 2024 PSUs awards:

	February 2025	July 2025	Modification Date: May 2024	Date of Grant: February 2024
Expected volatility	58.6 %	60 %	63.2 %	75.8 %
Dividend yield	0.00 %	0.00 %	0.00 %	0.00 %
Risk-free interest rate	4.22 %	3.74 %	4.72 %	4.19 %

The following table summarizes information regarding the PSUs granted under the EIP Plans for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
PSUs outstanding at December 31, 2023	402,701	$ 9.31
Granted (2)	312,843	$ 7.55
Forfeited	—	$ —
Vested	(107,044)	$ 2.63
PSUs outstanding at December 31, 2024	608,500	$ 9.58
Granted (3)	595,783	$ 6.31
Forfeited	(242,367)	$ 7.39
Vested	(285,491)	$ 6.48
PSUs outstanding at December 31, 2025	676,425	$ 8.79

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of PSUs issued for the year ended December 31, 2024 was $2.4 million based on a calculated fair value price ranging from $2.63 to $8.33 per share.
(3) The aggregate grant date fair value of PSUs issued for the year ended December 31, 2025 was $3.8 million based on a calculated fair value price ranging from $3.68 to $7.05 per share.

Compensation Expense

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

	For the Year Ended December 31,	
	2025	2024
Share-based compensation costs		
TSUs	$ 6,221	$ 4,877
PSUs	2,072	1,922
	$ 8,293	$ 6,799

Note 13. Leases

The Company enters into leases for office space, warehouse space and equipment in our corporate office and operating regions as well as vehicles, compressors and surface rentals related to our business operations. In addition, the Company has right-of-way leases to operate the San Pedro Bay Pipeline. For the year ended December 31, 2025, the Company leases qualify as operating leases and the Company did not have any existing or new leases qualifying as financing leases. Most of the Company's leases, other than the Company's corporate office lease, have an initial term and may be extended on a month-to-month basis after expiration of the initial term. Most of our leases can be terminated with 30-day prior written notice. The majority of our month-to-month leases are not included as a lease liability in the Company's balance sheet because continuation of the lease is not reasonably certain. Additionally, the Company elected the short-term practical expedient to exclude leases with a term of twelve months or less.

The Company corporate office lease does not provide an implicit rate. To determine the present value of the lease payments, the Company uses an incremental borrowing rate based on the information available at the inception date. To determine the incremental borrowing rate, the Company applied a portfolio approach based on the applicable lease terms and the current economic environment. The Company uses a reasonable market interest rate for the Company office equipment and vehicle leases.

For the year ended December 31, 2025 and 2024, the Company recognized approximately $2.1 million and $2.0 million, respectively, of costs relating to the operating leases in the Consolidated Statements of Operations.

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Supplemental cash flow information related to the Company's lease liabilities in included in the table below:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Non-cash amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,542	$ 1,216

The following table presents the Company's right-of-use assets and lease liabilities for the period presented:

	December 31, 2025	December 31, 2024
	(In thousands)	
Right-of-use asset	$ 2,998	$ 4,540
Lease liabilities:		
Current lease liability	1,184	1,784
Long-term lease liability	2,568	3,683
Total lease liability	$ 3,752	$ 5,467

The following table reflects the Company's maturity analysis of the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year (in thousands):

	Office and warehouse leases	Leased vehicles and office equipment	Total
2026	$ 1,223	$ 214	$ 1,437
2027	847	194	1,041
2028	728	12	740
2029	728	—	728
2030 and thereafter	364	—	364
Total lease payments	3,890	420	4,310
Less: interest	523	35	558
Present value of lease liabilities	$ 3,367	$ 385	$ 3,752

The weighted average remaining lease terms and discount rate for all of the Company's operating leases for the period presented:

	December 31,	
	2025	2024
Weighted average remaining lease term (years):		
Office and warehouse space	3.50	3.71
Vehicles	0.23	0.26
Office equipment	—	—
Weighted average discount rate:		
Office and warehouse space	6.20 %	5.43 %
Vehicles	0.84 %	1.31 %
Office equipment	— %	0.02 %

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Note 14. Supplemental Disclosures to the Consolidated Balance Sheet and Condensed Statement of Cash Flows

Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31, 2025	December 31, 2024
Accrued lease operating expense	$ 9,893	$ 13,845
Accrued general and administrative expense	7,616	6,281
Accrued severance expense	6,306	—
Accrued capital expenditures	5,335	5,191
Accrued production and ad valorem tax	2,085	2,827
Accrued commitment fee and other expense	1,799	2,395
Operating lease liability	1,184	1,784
Asset retirement obligations	300	1,377
Accrued current income tax payable	—	116
Accrued interest payable	—	292
Accrued liability - pipeline incident	—	5,534
Other	—	3,771
Accrued liabilities	$ 34,518	$ 43,413

Accounts Receivable

Accounts receivable consisted of the following at the dates indicated (in thousands):

	December 31, 2025	December 31, 2024
Oil and natural gas receivables	$ 23,010	$ 28,505
Insurance receivable - pipeline incident	—	4,722
Joint interest owners and other	10,048	8,214
Total accounts receivable	33,058	41,441
Less: allowance for doubtful accounts	(2,917)	(1,728)
Total accounts receivable, net	$ 30,141	$ 39,713

Supplemental Cash Flows

Supplemental cash flow for the periods presented (in thousands):

	For the Year Ended December 31, 2025	2024
Supplemental cash flows:		
Cash paid for interest, net of amounts capitalized	$ 9,775	$ 11,706
Cash paid for taxes	130	1,189
Supplemental non-cash activity:		
Accrued capital expenditures included in accounts payable and accrued expenses	9,820	12,049

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Note 15. Related Party Transactions

Related Party Agreements

There have been no transactions between the Company and a related person in which the related person had a direct or indirect material interest for the years ended December 31, 2025 and 2024.

Note 16. Segment Reporting

The Company's operations are all related to the exploration, development and production of oil and natural gas in the United States, from which the Company derives all of its revenues. The Company manages its business as a single reportable segment, as its operations are focused on assets with similar economic characteristics, production processes, types of purchasers, regulatory environment and customers which are consistent across the Company. Therefore, the Company aggregates its operating regions into one reportable segment.

The Chief Operating Decision Maker ("CODM") is the Company's Chief Executive Officer, who reviews the financial information on a consolidated basis. The CODM uses consolidated net income to assess financial performance, allocating capital and other resources. The CODM uses consolidated net income in the annual budgeting and monthly forecasting process. Additionally, our CODM is regularly provided information on lease operating expense, gathering, processing and transportation and taxes other than income. Other segment items primarily consists of DD&A, accretion expense, general and administrative expense, pipeline incident loss, loss (gain) on commodity derivative, interest expense and income tax expense (benefit). Our significant segment expenses and other segment items are derived from and can be found within the Consolidated Statement of Operations.

The following table provides financial information with respect to the Company's single reportable segment for the years ended December 31, 2025 and 2024:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Revenue	$ 263,361	$ 294,681
Less:		
Lease operating expense	141,324	142,950
Gathering, processing and transportation	17,795	18,427
Taxes other than income	15,870	20,895
Other segment items	44,404	99,463
Net income (loss)	$ 43,968	$ 12,946

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Note 17. Commitments and Contingencies

Litigation and Environmental

We are involved in various lawsuits, claims, government investigations and other legal proceedings that arise in the usual conduct of our business. These claims or proceedings can involve various types of parties, including governments, regulatory agencies, competitors, customers, suppliers, service providers, licensees, employees or stockholders, among others. These matters may involve antitrust, securities, pricing, public utility and transportation rates, taxes, environmental, commercial, contractual rights, licensing obligations, health and safety matters, employment matters, regulatory compliance and permits relating to the operations of our various plants and facilities, among others.

We assess these matters to determine if a contingent liability should be recorded. We accrue for estimated exposures to the extent they are both probable and reasonably estimable based on then-available information.

Predicting the outcome of claims and litigation, and estimating related costs and exposure, involves substantial uncertainties that could cause actual costs to vary materially from estimates and accruals. Matters often develop over a long period of time and expectations can change as a result of new findings, rulings, appeals, settlements, legal or regulatory changes or other factors. If the assessment of relevant factors changes, estimates may change, and it is not possible to determine the final outcome of these matters.

Although the Company is insured against various risks to the extent the Company believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify it against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2025 and 2024, the Company had no environmental reserves recorded.

Beta Pipeline Incident

In October 2021, the Company learned that a 4,000-foot section of the Company's pipeline approximately four miles off the coast of Newport Beach, California had been displaced with a maximum lateral movement of approximately 105 feet and that the pipeline had a 13-inch split, running parallel to the pipe, leading to the release of approximately 588 barrels of oil (the "Incident").

As previously disclosed, the Company reached resolutions regarding criminal and civil claims against it related to the Incident. The Company also reached resolutions related to civil claims the Company asserted against third parties related to the Incident. In addition, in December 2025, the Company paid $2.0 million pursuant to a settlement with PHMSA related to the Incident. Under the Oil Pollution Act of 1990, the Company's pipeline was designated by the U.S. Coast Guard as the source of the oil discharge and therefore the Company is financially responsible for certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. The Natural Resource Damage Assessment remains ongoing and therefore the extent, timing and cost related to such assessment are difficult to project. While the Company anticipates insurance will reimburse it for expenses related to the Natural Resource Damage Assessment, any potentially uncovered expenses may be material and could impact the Company's business and results of operations and could put pressure on its liquidity position going forward.

While it remains possible that federal agencies may in the future commence investigations or proceedings or may initiate enforcement actions seeking penalties or other relief, outside of the Natural Resource Damage Assessment, Amplify Energy has resolved any such investigations, proceedings or actions initiated to date.

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Total costs that the Company has incurred with respect to the Incident amount to approximately $202.4 million, which includes (i) response and remediation under the direction of the Unified Command, (ii) fines and penalties of $12.4 million resulting from the resolution of the federal and state of California matters, and (iii) certain legal fees.

On December 31, 2025, the Company no longer had an outstanding insurance receivable related to the pipeline incident loss and on December 31, 2024, the Company's insurance receivables were $4.7 million. For the year ended December 31, 2025, the Company incurred legal fees, loss load and other non-reimbursable expenses of $2.4 million that are classified as "Pipeline Incident Loss" on the Company's Consolidated Statements of Operations.

Sinking Fund Trust Agreement

Beta Operating Company, LLC, a wholly owned subsidiary, assumed an obligation with a third party to make payments into a sinking fund in connection with its 2009 acquisition of the Beta properties, the purpose of which is to provide funds adequate to decommission the portion of the San Pedro Bay Pipeline that lies within state waters and the surface facilities. Under the terms of the agreement, the operator of the properties is obligated to make monthly deposits into the sinking fund account in an amount equal to $0.25 per barrel of oil and other liquid hydrocarbon produced from the acquired working interest. Interest earned in the account stays in the account. The obligation to fund ceases when the aggregate value of the account reaches $4.3 million. As of December 31, 2025, the account balance included in restricted investments was approximately $4.6 million.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

Beta Operating Company, LLC has an obligation with BOEM in connection with the 2009 acquisition of the Beta properties. The Company supports this obligation with $161.3 million in A-rated surety bonds.

Pursuant to these additional collateral requirements, on December 15, 2021, the Company entered into two escrow funding agreements, a federal escrow funding agreement and a state escrow funding agreement, with its surety providers to fund interest-bearing escrow accounts on a quarterly basis to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. As long as we continue to comply with our obligations under such escrow agreements, the surety providers party thereto have agreed to stay requests of additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If any such additional collateral were requested, such additional collateral may negatively impact the Company's liquidity position.

In March 2024, the Company amended the federal escrow funding agreement to decrease the amount funded from $14.8 million per year to $8.0 million per year. There were no changes made to the state escrow funding agreement. The obligation ceases when the aggregate value of the account reaches $172.6 million. As of December 31, 2025, the Company has funded $35.6 million into the escrow accounts which is reflected in "Restricted Investments" on the Consolidated Balance Sheet. The table below outlines our funding commitment under these agreements at December 31, 2025 (in thousands):

	Payment Due by Period						
Funding commitment	**Total**	**2026**	**2027**	**2028**	**2029**	**2030**	**Thereafter [1]**
Federal escrow fund payments	$ 128,915	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 88,915
State escrow fund payments	8,083	1,034	1,034	1,034	1,034	1,034	2,913
Total sinking fund payments	$ 136,998	$ 9,034	$ 9,034	$ 9,034	$ 9,034	$ 9,034	$ 91,828

(1) The remaining payments will be made during the years of 2031 through 2042.

The expense related to the surety bonds is recorded in interest expense in the Company Statement of Consolidated Operations.

Operating Leases

The Company enters into leases for compressors, surface rentals, office space, warehouse space and equipment in our corporate office and operating regions. For the years ended December 31, 2025 and 2024, the Company recognized $9.6 million and $10.7 million of rental cost, respectively.

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See Note 13 for the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year.

Purchase Commitments

At December 31, 2025, the Company had a CO_2 purchase commitment with a third party associated with its Bairoil properties. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. The table below outlines its purchase commitments under these contracts based on pricing at December 31, 2025 (in thousands):

	Payment or Settlement Due by Period						
Purchase commitment	Total	2026	2027	2028	2029	2030	Thereafter
CO_2 minimum purchase commitment	$ 5,003	$ 1,775	$ 1,832	$ 1,396	$ —	$ —	$ —

Note 18. Income Tax

Amplify Energy is a corporation and, as a result, is subject to U.S. federal, state, and local income taxes.

On July 4, 2025, the U.S. enacted legislation referred to as the One Big Beautiful Bill("OBBBA"), which contains certain significant changes to U.S. corporate income tax laws that are generally effective for tax years beginning after December 31, 2024. These changes include, but are not limited to, the restoration of immediate expensing for domestic research and experimental ("R&E") expenses, the option to retroactively deduct certain previously capitalized R&E expenses, modifications to the business interest expense limitation, and the restoration of 100 percent bonus depreciation for qualified property placed in service after January 19, 2025. The impacts of the tax law changes from OBBBA are reflected in the Company's 2025 income tax provision; however, the changes affect timing only and do not change the total tax provision for the year ended December 31, 2025.

The Company adopted improvements to income tax disclosure (ASU 2023-09) on January 1, 2025. The adoption of the guidance did not impact the Company's financial position, results of operations, or cash flows.

The components of income tax benefit (expense) are as follows:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Current taxes:		
Federal	$ 1,377	$ 43
State	—	(275)
Total current income tax benefit (expense)	1,377	(232)
Deferred taxes:		
Federal	(12,486)	(2,433)
State	(5,762)	237
Total deferred income tax benefit (expense)	(18,248)	(2,196)
Total income tax benefit (expense)	$ (16,871)	$ (2,428)

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The actual income tax benefit (expense) differs from the expected amount computed by applying the federal statutory corporate tax rate of 21% for the year ended December 31, 2025, presented in accordance with the prospectively adopted ASU 2023-09 guidance, was as follows:

	For the Year Ended December 31, 2025	
	(In thousands)	%
U.S. federal statutory income tax	$ (12,776)	21.0 %
State tax, net of federal (a)	(4,552)	7.5 %
Tax credits:		
Marginal well credit	1,532	(2.5)%
Nontaxable or non-deductible items:		
Limit on executive compensation	(846)	1.4 %
Other	(229)	0.4 %
Total income tax benefit (expense)	$ (16,871)	27.8 %

(a) State taxes in California and Oklahoma made up majority (greater than 50 percent) of the tax effect in this category.

The actual income tax benefit (expense) differs from the expected amount computed by applying the federal statutory corporate tax rate of 21% in 2024 in accordance with the guidance prior to the adoption of ASU 2023-09 was as follows:

	For the Year Ended December 31, 2024
	(In thousands)
Expected tax benefit (expense) at federal statutory rate	$ (3,228)
Change in valuation allowance	—
Non-cash compensation	189
Limit on executive compensation	(492)
State income tax benefit (expense), net of federal benefits	(578)
State rate change, net of federal benefits	293
State prior year adjustments	255
Marginal well credit	1,137
Other	(4)
Total income tax benefit (expense)	$ (2,428)

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The Company's deferred income tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2025	2024
Deferred income tax assets:		
Property, plant & equipment	$ 18,355	$ 58,226
Net operating loss carryforward	203,714	180,902
Disallowed interest expense	8,957	7,494
Accrued liabilities	2,623	2,597
Other	5,111	4,993
Total deferred income tax assets:	238,760	254,212
Valuation allowance	—	—
Net deferred income tax assets	238,760	254,212
Deferred income tax liabilities:		
Derivatives	$ 4,682	$ 1,603
Other	744	1,009
Total deferred income tax liabilities	5,426	2,612
Net deferred income taxes	$ 233,334	$ 251,600

Net Operating Loss Carryforward. In connection with the merger with Midstates Petroleum Company in 2019, the Company was subject to IRC §382 loss limitations on pre-merger net operating loss ("NOL") and tax attributes. As of December 31, 2025, the Company's federal NOL carryforward of $790.8 million is subject to §382 loss limitations, of which $20.9 million will expire in 2037 and $769.9 million have no expiration. As of December 31, 2025, the Company has $149.7 million federal post-merger NOL carryforward. All post-merger NOLs are not subject to §382 loss limitations and do not expire.

As of December 31, 2025, the Company had approximately $88.9 million of state net operating loss carryovers which have different expirations dates starting in 2037.

Valuation Allowance. In assessing deferred tax assets, management considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. The assessment considers all available information including, among other things, historical and forecasted taxable income and operating history, the scheduled reversal of deferred tax liabilities and available tax planning strategies. As of December 31, 2025, the Company had three years of cumulative book income. Furthermore, management determined that the Company's ability to maintain long-term profitability despite near-term changes in commodity prices and capital and operating costs demonstrated that there is sufficient positive evidence to conclude that it is more likely than not that all net deferred tax assets are realizable.

Uncertain Income Tax Position. The Company must recognize the tax effects of any uncertain tax positions that the Company may adopt if the position taken by us is more likely than not sustainable based on its technical merits. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company had no unrecognized tax benefits as of December 31, 2025.

Tax Audits and Settlements. The Company's income tax years 2022 through 2024 remain open and subject to examination by the Internal Revenue Service (IRS). For state and local jurisdictions where the Company conducts operations, the Company's 2021 through 2024 tax years remain open and subject to examination. In certain jurisdictions where the Company operates through more than one legal entity, each of which may have different open years subject to examination.

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Note 19. Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization is as follows at the dates indicated.

	December 31,	
	2025	2024
	(In thousands)	
Evaluated oil and natural gas properties	$ 388,920	$ 942,981
Support equipment and facilities	154,954	150,511
Accumulated depletion, depreciation, and amortization	(355,121)	(708,836)
Total	$ 188,753	$ 384,656

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows for the periods indicated:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Property acquisition costs, proved	$ —	$ —
Property acquisition costs, unproved	—	—
Exploration	—	—
Development	82,055	70,945
Total	$ 82,055	$ 70,945

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

As required by the FASB and SEC, the standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and, therefore, may cause significant variability in cash flows from year to year as prices change.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

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Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations — 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.

We engaged CG&A to prepare our reserves estimates for all of our estimated proved reserves at December 31, 2025 and 2024. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

The weighted-average benchmark product prices used for valuing the reserves are based upon the average of the first-day-of-the-month price for each month within the period January through December of each year presented:

	2025	2024
Oil ($/Bbl):		
WTI (1)	$ 65.34	$ 75.48
NGL ($/Bbl):		
WTI (1)	$ 65.34	$ 75.48
Natural Gas ($/MMbtu):		
Henry Hub (2)	$ 3.39	$ 2.13

(1) The weighted average WTI price was adjusted by lease for quality, transportation fees, and a regional price differential.
(2) The weighted average Henry Hub price was adjusted by lease for energy content, compression charges, transportation fees, and regional price differentials.

The following tables set forth estimates of the net reserves for the periods indicated:

	For the Year Ended December 31, 2025			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of year	40,475	206,536	18,066	92,963
Production	(3,008)	(15,948)	(1,067)	(6,733)
Divestitures of reserves	(7,381)	(190,588)	(14,068)	(53,213)
Revision of previous estimates	5,530	—	(451)	5,079
End of year	35,616	—	2,480	38,096
Proved developed reserves:				
Beginning of year	31,392	197,621	17,879	82,207
End of year	22,141	—	2,480	24,621
Proved undeveloped reserves:				
Beginning of year	9,083	8,915	187	10,756
End of year	13,475	—	—	13,475

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	For the Year Ended December 31, 2024			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of year	41,078	226,878	19,185	98,077
Production	(3,060)	(16,836)	(1,278)	(7,144)
Revision of previous estimates	2,457	(3,506)	159	2,030
End of year	40,475	206,536	18,066	92,963
Proved developed reserves:				
Beginning of period	39,306	226,427	19,108	96,151
End of period	31,392	197,621	17,879	82,207
Proved undeveloped reserves:				
Beginning of period	1,772	451	77	1,926
End of period	9,083	8,915	187	10,756

Noteworthy amounts included in the categories of proved reserve changes in the above tables include:

- For the year ended December 31, 2025, reserves decreased by 54.9 MMBoe. This decline was primarily driven by 53.2 MMBoe in asset divestures, as well as 6.7 MMBoe from 2025 production and 6.5 MMBoe due to lower commodity prices. These reductions were partially offset by several positive adjustments including 3.2 MMBoe from lower Bairoil operating costs, 6 MMBoe from enhanced Beta drilling results, including the addition of 4 PUD locations, and 2.4 MMBoe from a four-year extension of Beta's economic life.

- The 5.1 MMBoe decrease in reserves for the year ended December 31, 2024 was primarily due to production of 7.1 MMBoe, a 6.9 MMBoe decrease as a result of changes in commodity prices and 4.8 MMBoe decrease primarily due higher electricity costs and shorter economic limit at Bairoil. This decrease was partially offset by the additional 31 (23 operated Beta) PUD locations which added 9.39 MMBoe, lower maintenance costs primarily at East Texas and Oklahoma of 3.36 MMBoe and a positive technical revision of 0.97 MMBoe.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

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The standardized measure of discounted future net cash flows is as follows:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Future cash inflows	$ 2,303,473	$ 3,818,663
Future production costs (1)	(1,454,650)	(2,217,101)
Future development costs (1)	(382,015)	(467,142)
Future income tax expense	(75,589)	(204,262)
Future net cash flows for estimated timing of cash flows	391,219	930,158
10% annual discount for estimated timing of cash flows	(56,096)	(321,919)
Standardized measure of discounted future net cash flows	$ 335,123	$ 608,239

(1) For the years ended December 31, 2025 and 2024, onshore abandonment costs are included in future production cost and offshore abandonment costs are included in future development costs.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the two-year period presented:

	For the Year Ended December 31,	
	2025	2024
	(In thousands)	
Beginning of year	$ 608,239	$ 626,130
Changes in prices and costs	(230,960)	(124,770)
Revisions of previous quantities	34,205	142,763
Sale of oil and natural gas produced, net of production costs	(81,075)	(100,658)
Divestiture of reserves	(209,013)	—
Net change in taxes	86,288	3,356
Accretion of discount	73,576	75,701
Change in production rates and other	21,963	(23,979)
Net changes in future development costs	8,450	(2,985)
Previously estimated development costs incurred	23,450	12,681
End of year	$ 335,123	$ 608,239