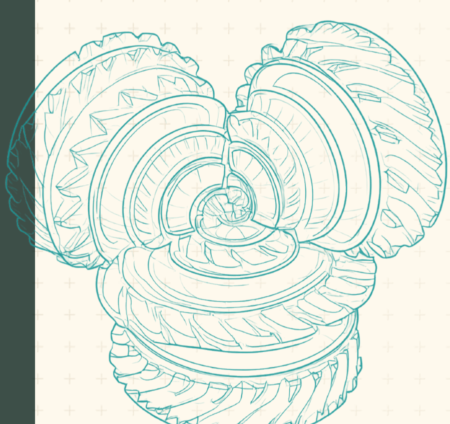
2025 Annual Report

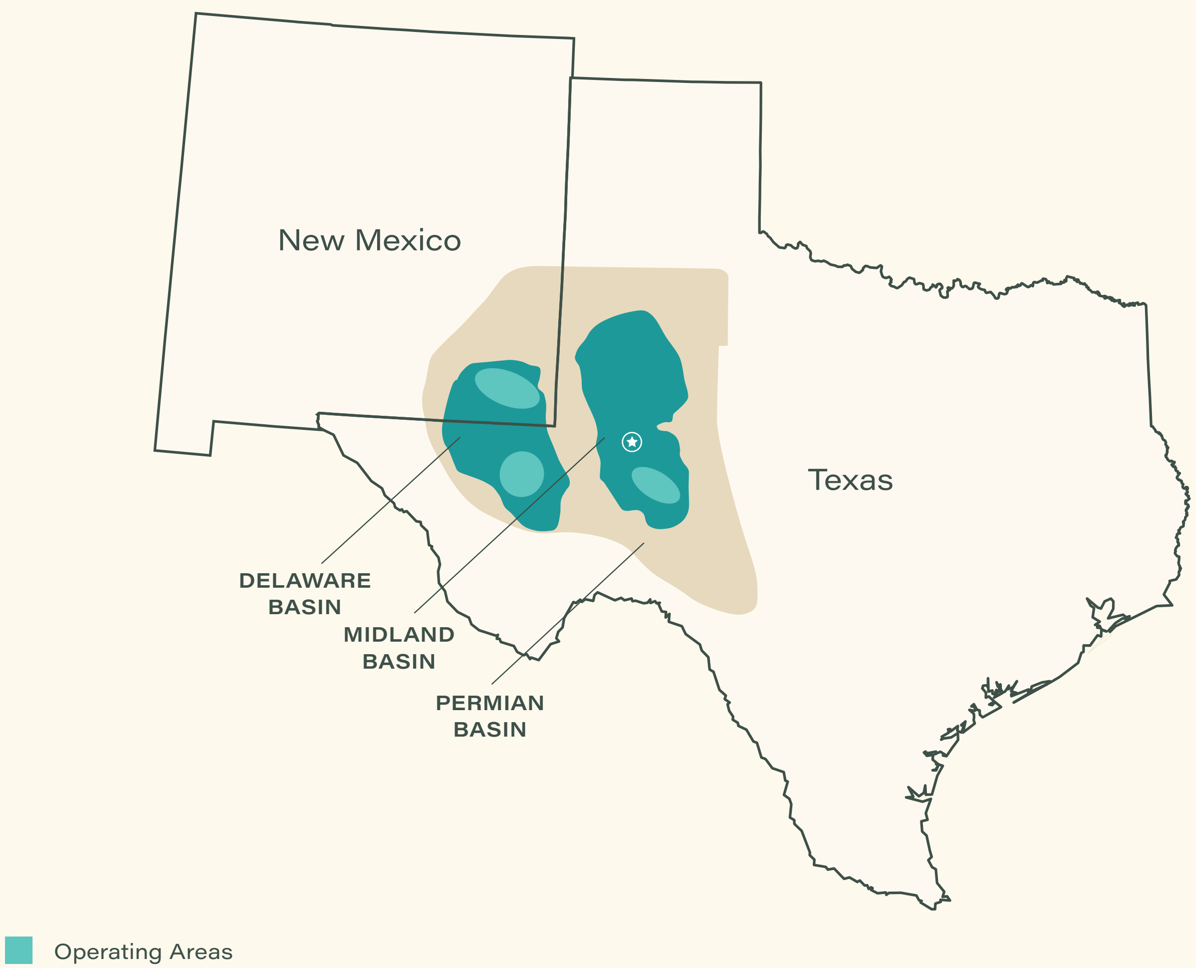
PERMIAN
RESOURCES

Delivering Leading Shareholder Returns



Headquartered in Midland, Texas, Permian Resources is an independent oil and natural gas company focused on delivering peer-leading returns through its low-cost leadership, proven acquisition strategy and high-quality asset base in the core of the Delaware Basin. With approximately 500,000 net acres across West Texas and Southeast New Mexico and over 400,000 Boe/d of total production, Permian Resources is the second-largest Permian Basin pure-play E&P. Permian Resources is listed on the NYSE as PR.

Area of Operations



~500,000	~415 MBoe/d	15+ Years
NET ACRES	FY'26E TOTAL PRODUCTION	HIGH-QUALITY INVENTORY

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

Commission file number 001-37697

PERMIAN RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**41-3338782**
(State of Incorporation)	(I.R.S. Employer Identification No.)

300 N. Marienfeld St., Suite 1000

Midland, Texas 79701

(Registrant's telephone number, including area code): (432) 695-4222

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, par value $0.0001 per share	PR	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post 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 definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act).

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $10,503,468,331 based on the closing price of the shares of common stock on that date. While shares of Class C Common Stock are not listed for public trading, they are exchangeable for shares of Class A Common Stock at any time on a share-for-share basis, and the calculation of aggregate market value assumes all outstanding shares of Class C Common Stock were exchanged for Class A Common Stock as of June 30, 2025.

As of February 20, 2026, there were 836,261,421 shares of total common stock outstanding, including 812,013,436 shares of Class A Common Stock, par value $0.0001 per share, and 24,247,985 shares of Class C Common Stock, par value $0.0001 per share.

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2025 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2025, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2025.

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GLOSSARY OF UNITS OF MEASUREMENTS AND CERTAIN INDUSTRY AND OTHER TERMS

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K, which are commonly used in the oil and natural gas industry:

Bbl. One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, NGLs or condensate.

Bbl/d. One Bbl per day.

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. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

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

Class A Common Stock. Shares of the Company's class A common stock, par value $0.0001 per share.

Class C Common Stock. Shares of the Company's class C common stock, par value $0.0001 per share.

Completion. The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to initiate production.

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

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality, gathering, processing and transportation fees and location of oil or natural gas.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Extension well. A well drilled to extend the limits of 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 or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

HSC. A natural gas benchmark price at the Houston Ship Channel hub.

MBbl. One thousand barrels of crude oil, NGLs or condensate.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Mont Belvieu price. An NGLs benchmark price at the Mont Belvieu hub.

NGL. Natural gas liquids. These are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated in these substances and sold.

NYMEX. The New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

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

Proved undeveloped reserves or PUD. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion.

Realized price. The price received for selling oil, NGL and natural gas production that reflects various factors including, but not limited to, transportation costs, regional market conditions and contractual differentials.

Reserves. 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.

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 reservoirs.

Royalty interest. An interest in an oil or gas property entitling the owner to its share of the production free of costs of exploration, development and production operations.

SOFR. Secured Overnight Funding Rate.

Spot market price. The cash market price without reduction for expected quality, location, transportation and demand adjustments.

Unproved reserves. Reserves attributable to unproved properties with no proved reserves.

Waha. A natural gas benchmark price in West Texas.

Wellbore. The hole drilled by a drill bit that is equipped for oil and natural gas production once the well has been completed. Also called well or borehole.

Working interest. The interest in an oil and gas property (typically a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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

WTI. West Texas Intermediate is a grade of crude oil used as a benchmark in oil pricing.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (the "Annual Report"), includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "goal," "plan," "target" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in *Item 1A. Risk Factors* in this Annual Report.

Forward-looking statements may include statements about:

- volatility of oil, NGL and natural gas prices or a prolonged period of low oil, NGL or natural gas prices and the effects of actions by, or disputes among or between, members of the Organization of Petroleum Exporting Countries ("OPEC"), such as Saudi Arabia and Venezuela, and other oil and natural gas producing countries, such as Russia, with respect to production levels or other matters related to the price of oil, NGLs and natural gas;
- political and economic conditions and events in or affecting other producing regions or countries, including the Middle East, Russia, Eastern Europe, Africa and South America, including recent developments in Venezuela and Iran;
- our business strategy and future drilling plans;
- our reserves and our ability to replace the reserves we produce through drilling and property acquisitions;
- our drilling prospects, inventories, projects and programs;
- our financial strategy, return of capital program, leverage, liquidity and capital required for our development program;
- our realized oil, NGL and natural gas prices;
- the timing and amount of our future production of oil, NGLs and natural gas;
- our ability to identify, complete and effectively integrate acquisitions of properties or businesses;
- our hedging strategy and results;
- our competition;
- our ability to obtain permits and governmental approvals;
- our compliance with government regulations, including those related to environmental, health and safety regulations and liabilities thereunder;
- our pending legal matters;
- the marketing and transportation of our oil, NGLs and natural gas;
- our leasehold or business acquisitions;
- cost of developing or operating our properties;
- our anticipated rate of return;
- general economic conditions;
- weather conditions in the areas where we operate;
- credit markets;
- our ability to make dividends, distributions and share repurchases;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of oil, NGLs and natural gas. Factors which could cause our actual results to differ materially from the results contemplated by forward-looking statements include, but are not limited to:

- commodity price volatility (including regional basis differentials);
- uncertainty inherent in estimating oil, NGL and natural gas reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- geographic concentration of our operations and/or consolidation in the oil and natural gas industry in the areas in which we operate and otherwise;
- changes in tariffs, trade barriers, price and exchange controls and other regulatory requirements;
- lack of availability of drilling and production equipment and services;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- risks related to acquisitions we may make from time to time, including the risk that we may fail to integrate such acquisitions on the terms and timing contemplated, or at all, and/or to realize our strategy and plans to achieve the expected benefits of such acquisitions;
- competition in the oil and natural gas industry for assets, materials, qualified personnel and capital;
- drilling and other operating risks;
- environmental and climate related risks, including seasonal weather conditions;
- changes to tax laws or interpretations thereof and the impact of such changes on us;
- regulatory changes, including those that may impact environmental, energy, and natural resources regulation;
- the possibility that the industry in which we operate may be subject to new or volatile local, state, and federal laws, regulations or policies that may affect our business (including additional taxes and changes in regulations and policies related to environmental, health, and safety, climate change, trade policy and tariffs) as a result of existing or developing political, environmental and social movements;
- restrictions on the use of water, including limits on the use of produced water and potential restrictions on the availability of water disposal facilities;
- availability of cash flow and access to capital;
- inflation;
- changes in our credit ratings or adverse changes in interest rates and associated changes in monetary policy;
- changes in the financial strength of counterparties to our credit agreement and hedging contracts;
- the timing of development expenditures;
- political and economic conditions and events in the U.S. and in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, including the conflict in Israel, Iran and their surrounding areas, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China, Russia and Venezuela, including any increased volumes of Venezuelan crude oil, and acts of terrorism or sabotage and the effects therefrom;
- changes in local, regional, national, and international economic conditions;
- technological advancement, including artificial intelligence (“AI”) and its application in our industry;
- security threats, including evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, third-party service provider failures, malicious software, data privacy breaches by employees, insiders or other with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and
- the other risks described in this Annual Report.

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

Should one or more of the risks or uncertainties described in this Annual Report occur, or should any underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

Risk Factors Summary

The following is a summary of the principal risks that could materially adversely affect our business, financial condition and results of operations. Refer to *Risk Factors* under Part I, Item 1A of this Annual Report for a more detailed description of each risk factor.

Risks Related to Commodity Prices

- Commodity prices are volatile, and a sustained period of low commodity prices for oil, natural gas and NGLs could adversely affect our business, financial condition and results of operations.
- If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.

Risks Related to Our Reserves, Leases and Drilling Locations

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.
- The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.
- Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.
- Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Risks Related to Our Operations

- Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, or at all, which could lead to a decline in our ability to access or grow production and reserves.
- Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.
- Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.
- Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.
- Our ability to produce crude oil, natural gas and NGLs economically in commercial quantities could be impaired if we are unable to recycle or dispose of the produced water we produce in an economical and environmentally safe manner.
- Our producing properties are concentrated in the Permian Basin, making us vulnerable to risks associated with operating in a single geographic area.
- The marketability of our production is dependent upon transportation and other facilities, most of which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.
- We have entered into multi-year agreements with some of our suppliers, service providers and the purchasers of our oil and natural gas, which contain minimum volume commitments. Any failure by us to satisfy the minimum volume commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.

- The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.
- We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.
- We depend on a small number of significant purchasers for the sale of most of our oil, natural gas and NGL production.
- We may incur losses as a result of title defects in the properties in which we invest.
- Multi-well pad drilling may result in volatility in our operating results.

Risks Related to Our Derivative Transactions, Debt and Access to Capital
- Our derivative activities could result in financial losses or could reduce our earnings.
- Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on our outstanding debt.
- We may not be able to generate sufficient cash to service all of OpCo's indebtedness and may be forced to take other actions to satisfy OpCo's obligations under applicable debt instruments, which may not be successful.
- Restrictions in OpCo's existing and future debt agreements may limit our growth and ability to take certain activities.
- If OpCo is unable to comply with the restrictions and covenants in the agreements governing its indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that OpCo has borrowed.
- Any significant reduction in the borrowing base under OpCo's revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.
- If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Risks Related to Legislative and Regulatory Initiatives
- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.
- Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.
- Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.
- A negative shift in investor sentiment towards the oil and natural gas industry and increased attention to sustainability and conservation matters may adversely impact our business.
- Any restrictions on oil and natural gas development on federal lands have the potential to adversely impact operations.

Risks Related to Our Common Stock and Capital Structure
- Our cash flow is dependent upon the ability of our operating subsidiaries to make cash distributions to us, the amount of which will depend on various factors.
- If we experience any material weakness or otherwise fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, stockholders could lose confidence in our financial reporting, which would harm our business and the value of our Class A Common Stock.
- There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.
- The declaration of dividends and any repurchases of our common stock are each within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.
- Provisions contained in our Charter and Bylaws, as well as provisions of Delaware law, could impair a takeover attempt, which may adversely affect the market price of our common stock.
- The Charter designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for substantially all actions and proceedings that may be initiated by stockholders, which could limit shareholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

Permian Resources Corporation is an independent oil and natural gas company focused on driving returns to our stockholders through the acquisition, optimization and development of high-return crude oil and associated liquids-rich natural gas reserves. Throughout this Annual Report, unless the context otherwise indicates, all references to the "Company," "Permian Resources," "we," "us," or "our" refer to Permian Resources Corporation and its consolidated subsidiary, Permian Resources Operating, LLC ("OpCo").

Our principal business objective is to generate leading shareholder returns by leveraging our technical expertise and operational flexibility to optimally develop our oil and natural gas resources. We are focused on enhancing our high-quality scaled asset base, executing a capital-efficient development program, maintaining a conservative balance sheet and financial policy, and maximizing returns to our shareholders. We also look for opportunities to optimize our portfolio of high-return, long-life inventory through accretive acquisitions that meet our strategic and disciplined financial objectives.

Description of Our Properties

Our assets are located in the Permian Basin, with a concentration in the core of the Delaware Basin consisting of large, contiguous acreage blocks in West Texas and New Mexico. As of December 31, 2025, we have approximately 480,000 net leasehold acres and over 105,000 net royalty acres. Approximately 67% of our net leasehold acreage is located in Texas and the remaining 33% is located in New Mexico.

2025 Acquisitions and Capital Investments

On June 16, 2025, we completed an acquisition of approximately 13,000 net leasehold acres with Apache Corporation for an unadjusted purchase price of $608 million. The acreage acquired is predominately located directly offsetting our existing asset position in the core of our New Mexico operating area.

Additionally, during the year ended December 31, 2025, we completed multiple acquisitions of oil and natural gas properties for a cumulative adjusted purchase price of approximately $471.1 million. These acquisitions are part of our ongoing bolt-on and grassroots acquisition programs.

During 2025 we invested $1.97 billion of capital expenditures in our developmental drilling and completion program resulting in 190.7 net developmental wells being placed on production.

Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The pre-tax PV 10% amounts shown in the following table are not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated, due to a number of factors. The following table should be read along with *Item 1A. Risk Factors* in this Annual Report.

The following table summarizes estimated proved reserves, pre-tax PV 10%, and standardized measure of discounted future cash flows for the periods indicated:

	December 31, 2025	December 31, 2024	December 31, 2023
Proved developed reserves:			
Oil (MBbls)	327,545	312,641	271,328
NGL (MBbls)	215,469	196,775	192,368
Natural gas (MMcf)	1,506,487	1,422,468	1,441,914
Total proved developed reserves (MBoe)(1)	794,095	746,494	704,015
Proved undeveloped reserves:			
Oil (MBbls)	151,665	146,540	122,008
NGL (MBbls)	79,931	61,543	45,046
Natural gas (MMcf)	543,644	434,283	324,176
Total proved undeveloped reserves (MBoe)(1)	322,203	280,463	221,083
Total proved reserves:			
Oil (MBbls)	479,210	459,181	393,336
NGL (MBbls)	295,400	258,318	237,414
Natural gas (MMcf)	2,050,131	1,856,751	1,766,090
Total proved reserves (MBoe)(1)	1,116,298	1,026,957	925,098
Proved developed reserves %	71 %	73 %	76 %
Proved undeveloped reserves %	29 %	27 %	24 %
Reserve values (in millions):			
Standard measure of discounted future net cash flows	$ 8,365.5	$ 9,342.3	$ 9,526.2
Discounted future income tax expense	1,073.8	1,488.1	1,581.5
Total proved pre-tax PV 10%(2)	$ 9,439.3	$ 10,830.4	$ 11,107.7

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Total proved pre-tax PV 10% ("Pre-tax PV 10%") is a supplemental non-GAAP financial measure as defined by the U.S. Securities and Exchange Commission ("SEC") and is derived from the standardized measure of discounted future net cash flows (the "Standardized Measure"), which is the most directly comparable U.S. generally accepted accounting principles ("GAAP") financial measure. Pre-tax PV 10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe Pre-tax PV 10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our Pre-tax PV 10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. However, Pre-tax PV 10% is not a substitute for the Standardized Measure. Our Pre-tax PV 10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

Proved Undeveloped Reserves. Our proved undeveloped ("PUD") reserves increased by 41.7 MMBoe on a net basis from December 31, 2024 to December 31, 2025, and the following table provides a reconciliation of the changes to our PUD reserves that occurred during the year:

(MBoe)	2025
Proved undeveloped reserves at January 1, 2025	280,463
Transfers to proved developed reserves	(84,293)
Revisions to previous estimates	(27,232)
Extensions and discoveries	142,710
Purchase of reserves in place	10,555
Proved undeveloped reserves at December 31, 2025	322,203

The increase in proved undeveloped reserves during 2025 was primarily attributable to adding 142.7 MMBoe of PUD reserves through extensions and discoveries stemming from our continuous drilling program, which added new locations primarily in the various Bone Spring and Wolfcamp formations on our acreage position in the Permian Basin. Additionally, we added 10.6 MMBoe of PUD reserves from properties acquired during the year. These positive additions were partially offset by converting 84.3 MMBoe of PUD reserves to proved developed reserves during 2025, for which we spent $772.5 million in capital expenditures. Additionally, PUD reserves were reduced during the year by a net amount of 27.2 MMBoe from revisions to previous estimates mainly related to (i) 36.0 MMBoe of PUD reserves that were reclassified to unproved reserves or removed due to changes made to our development plan, and (ii) 10.2 MMBoe of reduced PUD reserves from lower average commodity prices for the year ended 2025. These downward revisions were partially offset by 19.0 MMBoe of positive revisions primarily related to timing and performance. All of our PUD locations are scheduled to be drilled within five years of their initial booking. Our PUD to proved developed reserves conversion rate was 30% in 2025.

For additional information and for a discussion of material changes on our total proved reserves, see *Supplemental Information About Oil & Natural Gas Producing Activities*, Item 8. Financial Statements and Supplementary Data of this Annual Report.

Preparation of Reserve Estimates

Our proved reserves are estimated by an independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Reserve estimates are prepared in accordance with the definitions and regulations of the SEC and the Financial Accounting Standards Board (the "FASB") using a deterministic method, which includes decline curve analysis, production performance analysis, offset analogies, and in some cases a combination of these methodologies.

Controls over Reserve Estimation

We maintain adequate and effective internal controls over the reserve estimation process and the underlying data which the reserve estimates are based upon. Our reserves estimation process is coordinated by our internal reserves department, which consists of qualified petroleum engineers and is overseen by our Reserves Manager. Reserve information, including models and other technical data, are stored on a secured database on our network. Certain non-technical inputs used in the reserves estimation process such as ownership interest percentages, oil and natural gas production, commodity prices, price differentials, operating and development costs and plug and abandonment estimates are obtained by other departments. Annually, our internal reserves department prepares a preliminary reserve database and meets with NSAI to discuss the assumptions and methods to be used in the year-end proved reserve estimation process and to review field performance and our future development plans. Following this review, the reserve database and supporting data is furnished to NSAI for their independent estimates and final report.

Qualifications of Responsible Technical Persons

Our Reserves Manager, Natalie La, is responsible for overseeing the preparation of the reserves estimates. Ms. La has held this position at Permian Resources since October 2025 and has over 10 years of relevant experience in reservoir engineering and reserve estimation. She holds a Master's degree in Petroleum Engineering from the University of Texas at Austin and is a Registered Professional Engineer.

NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Ms. Lily W. Cheung and Mr. Zachary R. Long. Ms. Cheung, a Licensed Professional Engineer in the State of Texas (No. 107207), has been practicing consulting petroleum engineering at NSAI since 2007 and has over 4 years of prior industry experience. She graduated from Massachusetts Institute of Technology in 2003 with a Bachelor of Science Degree in Mechanical Engineering and from University of Texas at Austin in 2007 with a Master of Business Administration Degree. Mr. Long, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 11792), has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. He graduated from University of Louisiana at Lafayette in 2003 with a Bachelor of Science Degree in Petroleum Geology and from Texas A&M University in 2005 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production

The following table sets forth information regarding net production of oil, NGLs and natural gas, and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2025	2024	2023
Net production:			
Oil (MBbls)	66,364	58,276	35,560
NGL (MBbls)	35,773	30,636	15,569
Natural gas (MMcf)	247,045	220,900	119,182
Total (MBoe)(1)	143,311	125,730	70,992
Average sales price (excluding effect of hedges):			
Oil (per Bbl)	$ 64.06	$ 74.87	$ 75.84
NGL (per Bbl)	18.41	20.81	18.12
Natural gas (per Mcf)(2)	0.63	—	1.19
Total per Boe(1)	$ 35.34	$ 39.77	$ 43.96
Operating costs per Boe:			
Lease operating expenses	$ 5.26	$ 5.45	$ 5.26
Severance and ad valorem taxes	2.72	3.00	3.39
Gathering, processing and transportation expenses	1.40	1.46	1.26

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Natural gas average sales price includes the effects of $0.10 per Mcf of purchased gas sales for the year ended December 31, 2025.

Acreage

The following table sets forth information as of December 31, 2025 relating to our gross and net developed and undeveloped leasehold acreage. Developed acreage consists of acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. The acreage classified as developed in the table below is considered such due to the existence of producing wells in a specific formation underlying such acreage. However, utilizing horizontal drilling, we are able to develop multiple stacked shale formations underlying the same surface acreage resulting in more development potential of such developed acreage.

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
489,382	392,072	163,230	89,680	652,612	481,752

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the 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.

Certain leases included in the undeveloped acreage set forth in the table above may expire at the end of their respective primary lease terms unless production is established within the spacing units covering the acreage, the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates, or pursuant to other terms of the lease agreements. As of December 31, 2025, approximately 10,000 net acres of our total net acreage may expire over the next five years. However, our development program includes the review of any lease before the contractual expiration date and in cases where additional time may be required to fully evaluate acreage, we have generally been successful in obtaining extensions. Such expirations have not had a material impact on our development plans or reserves and we do not expect them to have a future adverse impact based on our current operations.

Productive Wells

As of December 31, 2025, we owned an approximate 84% average working interest in 3,473 gross (2,923 net) operated productive wells, an approximate 12% average working interest in 1,203 gross (147 net) non-operated productive wells and a royalty interest only in 297 additional wells. The wells we own a working interest in are primarily oil wells (4,042 gross, 2,693 net productive oil wells) that produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells placed on production, for the periods indicated. Productive wells are exploratory, development or extension wells that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are exploratory, development or extension wells that prove to be incapable of producing hydrocarbons in sufficient quantities to justify incurring the costs associated with completion as an oil or gas well.

	Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	242	190.7	275	205.7	183	150.2
Dry[(1)]	1	0.8	—	—	2	1.8
	243	191.6	275	205.7	185	152.0
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	—	—	—	—	—	—
Total	243	191.6	275	205.7	185	152.0

(1) The developmental dry hole category includes wells that were unsuccessful due to mechanical issues that occurred during drilling.

As of December 31, 2025, we had 159 gross (117.7 net) operated wells in the process of drilling or completion.

Delivery Commitments

The table below summarizes our long-term firm sales agreements, which provides for gross firm sales over the contractual term:

NGL Volume Commitments[1]

Period	Total (Bbls)	Daily (Bbls/d)
2026	3,285,000	9,000
2027	3,285,000	9,000
2028	819,000	9,000
Total	7,389,000	

Natural Gas Volume Commitments[1]

Period	Total (Mcf)	Daily (Mcf/d)
2026	29,200,000	80,000
2027	27,375,000	75,000
2028	7,290,000	20,000
2029	1,825,000	5,000
2030	1,825,000	5,000
Thereafter[2]	1,825,000	5,000
Total	69,340,000	

(1) Above volumes represent the total gross volumes we are required to deliver pursuant to agreements with carriers, which gross volumes are not comparable to our net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation* in this Annual Report, as amounts therein are reflected net of all royalties, overriding royalties and production due to others.

(2) These agreements have a contractual term through December 31, 2031.

These committed volumes are subject to under-delivery fees that would result in a financial obligation equal to a specified rate, subject to certain inflation factors. We expect our production and reserves will continue to be the primary means of fulfilling our future commitments. Refer to *Note 13—Commitments and Contingencies* under Part II, Item 8 of this Annual Report for additional information on our delivery commitments.

Title to Properties

We believe that we have satisfactory title to substantially all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, working and other outstanding interests customary in the industry. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Marketing and Customers

We market the majority of the production from properties we operate on account of both ourselves and that of the other working interest owners in these properties. We generally sell our oil, NGL and natural gas production to purchasers at prevailing market prices, which in certain cases are adjusted for contractual differentials, and the majority of our revenue contracts have terms greater than twelve months.

We normally sell production to a relatively small number of customers, as is customary in our business. The table below summarizes the purchasers that accounted for 10% or more of our total net revenues in at least one of the periods presented:

	Year Ended December 31,		
	2025	2024	2023
Enterprise Crude Oil, LLC	34 %	19 %	30 %
Shell Trading (US) Company[1]		31 %	20 %
BP America[1]		11 %	20 %

(1) During the year ended December 31, 2025, these customers accounted for less than 10% of our total net revenues.

During these periods, no other purchaser accounted for 10% or more of our net revenues. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term. However, since crude oil and natural gas are fungible products with well-established markets and numerous purchasers that are based on current demand for oil and natural gas, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition or results of operations.

Competition

The oil and natural gas industry is a highly competitive environment. We compete with both major integrated and other independent oil and natural gas companies in all aspects of our business including exploring, developing and operating our properties as well as transporting and marketing our production. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect the supply and demand for oil and natural gas production, such as price fluctuations (including basis differentials), domestic and foreign political conditions, weather conditions, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the areas of our production. The majority of our oil production is sold at the wellhead as it enters third-party gathering pipelines. The purchaser then transports the oil by pipeline or truck to a tank farm, another pipeline or a refinery. Our natural gas is either transported by gathering lines from the wellhead to a central delivery point and is then gathered by third-party lines to a gas processing facility or gathered by a third-party directly from the wellhead.

Regulation of the Oil and Natural Gas Industry

Our operations are subject to extensive federal, state and local laws and regulations. All of the jurisdictions in which we own or operate producing properties have statutory provisions regulating the development and production of oil and natural gas, including, but not limited to, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations including, but not limited to, the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. Federal and state environmental and occupational health and safety laws impose certain performance or compliance standards, work practices and recordkeeping and reporting obligations on our operations.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted, unforeseen environmental, health or safety incidents may occur and past non-compliance may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional regulatory proposals and proceedings affecting the oil and natural gas industry are regularly considered by Congress, the states, regulatory authorities, including the Federal Energy Regulatory Commission ("FERC") and the U.S. Environmental Protection Agency (the "EPA"), and the courts. We cannot predict when or whether any such outcomes of these proceedings will materially affect our operations.

Regulation of Production of Oil and Natural Gas

The production of oil, NGLs and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in New Mexico and Texas, which regulate drilling and operating activities by, among other things, requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of New Mexico and Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, NGLs and natural gas that we can produce from our wells and to limit the number of wells or the locations where we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, New Mexico and Texas impose a production or severance tax with respect to the production and sale of oil, NGLs and natural gas within their jurisdiction.

Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, and as a result we do not expect compliance with such regulatory requirements to affect our operations in any way that is of material difference from our competitors who are similarly situated. However, the failure to comply with these rules and regulations can result in substantial penalties.

Regulation of Sales and Transportation of Oil

Sales of oil, NGLs and condensate from our producing wells are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Sales of oil are affected by the availability, terms and conditions and cost of transportation services. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates the transportation in interstate commerce of crude oil, petroleum products, NGLs and other forms of liquid fuel under the Interstate Commerce Act.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We rely on third-party pipeline systems to transport the majority of crude oil produced by our wells. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other oil producers and marketers with which we compete.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act of 1978 (the “NGPA”) and culminated in adoption of the Natural Gas Wellhead Decontrol Act, which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 (the “NGA”), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The federal Energy Policy Act of 2005 (the “EP Act of 2005”) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amended the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provided FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increased FERC’s civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. The maximum civil penalty authority under the NGA and NGPA is adjusted annually for inflation; as of January 14, 2025, FERC may now assess civil penalties under the NGA and NGPA of $1,584,648 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670 to implement the anti-market manipulation provision of the EP Act of 2005. The issued rules make it unlawful, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

We are required to observe such anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and those enforced by the US Commodity Futures Trading Commission (the “CFTC”) under the Commodity Exchange Act, as amended (the “CEA”) and CFTC regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce, as well as the market for financial instruments on such commodity, such as futures, options and swaps. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. 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.

Natural gas gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states. Section 1(b) of the NGA exempts companies that provide natural gas gathering services from regulation by FERC as a "natural gas company" under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, or vice versa, and depending on the scope of that decision, our costs of delivering gas to point-of-sale locations may increase. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action that FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, state and local laws and regulations governing the occupational safety and health aspects of our operations, the discharge of materials into the environment, and protection of the environment and natural resources (including threatened and endangered species and their habitats). Numerous governmental entities, including 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 costly investigation or actions. These laws and regulations may, among other things, (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentrations of various substances that can be released into the environment or injected into formations in connection with drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; (iv) require remedial measures to prevent or mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws and regulations, as amended from time to time, to which our business operations are or may be subject, and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Handling Wastes

The Resource Conservation and Recovery Act ("RCRA") and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and nonhazardous solid wastes. Pursuant to rules issued by the EPA, states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and other wastes associated with the exploration, development and production of oil, NGLs and natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes currently classified as nonhazardous solid wastes could be re-classified as hazardous wastes in the future, as RCRA requires the EPA to periodically review (and revise if necessary) such determinations. Any such reclassification could increase our costs (and those of the oil, NGL and natural gas exploration and production industry) to manage and dispose of wastes, and materially adversely affect our results of operations and financial position. While the costs of managing waste (including hazardous waste) may be insignificant, we do not believe that our costs in this regard are materially more burdensome than those of similarly situated companies.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or the legality of conduct, on classes of persons considered responsible for the release of a hazardous substance into the environment. These persons include the current and former owners or operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for remediation costs, damages to natural resources, and 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 from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We may generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease or operate numerous properties that have been used for oil, NGL and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Clean Water Act (the "CWA") and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills, leaks of hazardous substances and placement of dredge and fill material into state waters and waters of the United States ("WOTUS"). 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. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other CWA requirements and analogous state laws and regulations.

There continues to be uncertainty as to the federal government's jurisdictional reach under the CWA, including with respect to wetlands. The EPA and the U.S. Army Corps of Engineers (the "Corps") under the Obama, Trump and Biden administrations have pursued multiple rulemakings since 2015 in the attempt of determining the scope of such reach. Following legal actions, implementation of the most recent rule is currently split across the country. The rule is subject to an injunction in 27 states, including Texas, resulting in implementation of the pre-2015 rule adjusted to take into account jurisdictional limitations decided by the Supreme Court in *Sackett v. EPA*. The other 23 states, including New Mexico, are subject to a WOTUS-defining rule published in September 2023. The Corps is currently pursuing a new post-*Sackett* rulemaking, the ultimate consequence of which cannot be predicted at this time.

Many of our customers and service providers rely on permits obtained under the CWA for their oil and gas pipeline projects, the most common of which is Nationwide Permit 12 ("NWP 12"). NWP 12 is, from time to time, renewed or modified by the Corps, whose actions in turn may be subject to litigation. NWP 12 is expected to be reissued by the Corps in 2026. To the extent any action expands the scope of the CWA in areas where we or our suppliers, customers or service providers operate or imposes new or enhanced permitting requirements, our operations could be adversely impacted by increased compliance costs and energy infrastructure project delays or cancellations.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (the "OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening WOTUS or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Subsurface Injections

In the course of our operations, we produce water in addition to crude oil, NGLs and natural gas. Produced water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near below-ground disposal wells used for the injection of natural gas- and oil-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety. While we cannot predict the ultimate outcome of these actions, any action that temporarily or permanently restricts the availability of disposal capacity for produced water or other fluids may increase our costs or have other adverse impacts on our operations. These seismic events have also led to an increase in tort lawsuits filed against exploration and production companies, as well as the owners of underground injection wells. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability; however, these costs are commonly incurred by all oil, NGL and natural gas producers, and we do not believe that the costs associated with the disposal of produced water will affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Air Emissions

The federal Clean Air Act ("CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These 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 need to obtain permits has the potential to delay the development of our projects. Recently, there has been increased regulation with respect to air emissions from the oil and natural gas sector. For example, the EPA has promulgated rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS"), and a separate set of requirements to address certain hazardous air pollutants frequently associated with oil and natural gas production and processing activities pursuant to the National Emissions Standards for Hazardous Air Pollutants program.

The EPA's 2024 updates to NSPS regulations applicable to oil and natural gas sectors require, among many things, the phase out of routine flaring of natural gas from new oil wells, routine leak monitoring, detection and repair obligations at all well sites and compressor stations, and reductions in emissions via capture and control systems or the use of zero-emission equipment in certain processes. The 2024 NSPS rule also establishes a "Super Emitter Response Program" that would trigger certain operator investigation and repair requirements in response to an emissions event exceeding 200 pounds per hour, as detected by regulatory authorities or qualified third parties. The 2024 NSPS rule further obligates states to impose these requirements on existing sources through their respective state implementation plans. In March 2025, the EPA announced an intent to reconsider the 2024 NSPS rule's provisions into late 2026 or early 2027. Because the 2024 NSPS and 2025 deadline extension rules are subject to ongoing litigation and the EPA is currently reconsidering the 2024 NSPS rule, future implementation of these regulations is uncertain at this time. The EPA's NSPS regulatory program, and any new, more stringent emissions regulations promulgated by the EPA or any other federal or state agency, could raise our costs of regulatory compliance.

The EPA is also required by the CAA to set National Ambient Air Quality Standards ("NAAQS") for six principal pollutants that are considered harmful to public health. Whether the air quality in a particular region is in "attainment" with the NAAQS for a particular pollutant impacts the stringency of certain air quality controls and restrictions in that area. The EPA periodically reviews each NAAQS and determines whether a revision is necessary. For example, in February 2024, the EPA issued a final rule lowering the primary annual NAAQS for particulate matter 2.5 from 12.0 µg per cubic meter to 9.0 µg per cubic meter. While the areas in which we operate were not likely to be redesignated as a result of this change, any adoption of a more stringent NAAQS has the potential to result in more restrictive permitting and pollution control requirements, increased permitting delays, or emission offset requirements.

Compliance with one or more of these and other air pollution control and permitting requirements and rules has the potential to delay the development of natural gas, oil and NGL projects and increase our costs of development and production, which costs could be significant.

Regulation of GHG Emissions and Climate Change

In response to findings that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") preconstruction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions and impose performance standards for reducing methane emissions from oil and gas operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from large GHG emission sources in the United States, including certain onshore and offshore natural gas, oil and NGL production sources, which include certain of our operations. The Bureau of Land Management ("BLM") has also, from time to time, considered or adopted rules regulating GHG emissions from oil and gas operation on federal lands. Nevertheless, there continues to be uncertainty surrounding the federal regulation of methane and other GHG emissions. Federal policy towards GHG emissions, and regulation thereunder, has varied significantly between the past several Presidential administrations. The current Trump administration has expressed a policy preference of limiting or rescinding regulations concerning GHG emissions and promulgated a final rule, in February 2026, repealing the EPA's 2009 "Endangerment Finding" that forms the basis for most of the EPA's GHG-related rules. However, whether or how such policies and the EPA's rescission of its "Endangerment Finding" will be implemented and if they will survive any potential legal challenges, or whether future administrations or Congress may pursue new GHG emissions regulations, cannot be predicted at this time.

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, including proposals adopting cap-and-trade programs, carbon taxes, climate-related mitigation funds, and regulations that directly limit GHG emissions from select sources, no significant legislation has been adopted at the federal level. While Congress previously enacted the Inflation Reduction Act of 2022 (the "IRA") to advance climate-related objectives and provide financial support for alternative or lower GHG-emitting energy production, many of these incentives were repealed or otherwise modified following the change in Presidential administrations and the enactment of the One Big Beautiful Bill Act in 2025 ("OBBBA"). However, any similar or future climate-related legislation and accompanying policy initiatives could increase operating costs within the oil and gas industry or accelerate a transition away from fossil fuels, which could in turn reduce demand for our products and adversely affect our business and results of operations.

In the absence of such federal climate legislation, a number of state and regional climate-related initiatives and regulations have emerged. In New Mexico, recent legislation codified a regulatory provision requiring operators to capture 98% of their produced natural gas. Routine venting and flaring is also prohibited in New Mexico. State, regional and local governments may also elect to continue to participate in international climate change initiatives, despite the Trump administration finalizing the United States' withdrawal from such initiatives in 2026. The participation in, or support for, climate-related policies and initiatives by politicians, regulators, financial institutions, consumers, and other stakeholders could increase opposition against, reduce funding for or lead to new limitations on, fossil fuel exploration and production activities.

Although it appears unlikely in the near term that new federal laws or regulations may be adopted or issued to address GHG emissions, any such future laws, regulations or legal requirements imposing reporting or permitting 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, as well as delay or restrict our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the natural gas, oil and NGLs we produce and lower the value of our reserves.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil, NGLs and natural gas from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued permitting guidance under the SDWA for certain hydraulic fracturing activities involving the use of diesel fuels and published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, the regulation of hydraulic fracturing has continued at the state level. Many states, including Texas and New Mexico, have promulgated rules related to the public disclosure of substances used in hydraulic fluid and testing requirements for water wells near drilling sites. Some local governments have also sought to regulate the time, place, and manner of drilling and hydraulic fracturing activities within their jurisdictions, or to ban hydraulic fracturing within their jurisdiction altogether. In the event that new federal or more stringent state or local regulations relating to the hydraulic fracturing process are adopted in areas where we operate, we may incur additional costs to comply with such requirements that may be significant in nature, and we also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of our exploration, development, or production activities.

Activities on Federal and State Lands

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, require compliance with detailed federal regulations and orders, including relating to plugging and abandonment, and are frequently subject to permitting delays. Federal oil and gas leasing programs have also been, from time to time, suspended by executive order or subject to collateral litigation.

Operations on federal lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. The NEPA evaluation process has followed regulations issued by the Council on Environmental Quality ("CEQ") for many years. However, in January 2026, CEQ issued a final rule rescinding its regulations following a D.C. Circuit decision limiting CEQ's authority to promulgate such rules and regulations. Further, the U.S. Supreme Court's recent *Seven County* decision directed lower courts to give substantial deference to the reviewing agency's select scoping decisions in NEPA reviews. The ultimate outcome of these developments are not yet clear.

Our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations and the support of infrastructure projects that may be subject to the requirements of NEPA. This process, including any additional requirements or procedures that may be included in the process or litigation over the sufficiency of the process, has the potential to delay or limit, or increase the cost of, the development of natural gas, oil and NGL projects. Individual authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in the Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial. However, any such adverse regulatory developments are expected to have no more than a minimal impact on our results, given our limited exposure of leases on federal lands.

Protected Species

The federal Endangered Species Act ("ESA") and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"). The extent of regulatory restrictions imposed by these laws depends on the implementing regulations promulgated by the U.S. Fish and Wildlife Service ("USFWS") and the National Marine Fisheries Service ("NMFS"), which have varied between recent Presidential administrations. Congress, from time to time, has also considered legislation to reform certain aspects of the ESA and MBTA.

We may conduct operations on oil and natural gas leases in areas where certain species that are , were or are candidates to be listed as threatened or endangered are known to exist, including the Dunes Sagebrush Lizard and Lesser Prairie Chicken (the listing decisions of which are currently subject to ongoing litigation), and where other species that potentially could be listed as threatened or endangered under the ESA may exist. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Occupational Safety and Public Right-to-Know Regulations

We are subject to the requirements of the Occupational Safety and Health Act, as implemented by the Occupational Safety and Health Administration ("OSHA"), and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right-to-Know Act, the EPA's Risk Management Program rule and comparable state statutes, and their implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other activities and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our development activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Human Capital Resources

We aim to attract and retain top-tier talent in the oil and gas sector and empower our employees to be innovators in our industry. As of December 31, 2025, we had approximately 515 total employees. In addition, we hire independent contractors on an as needed basis. We are not a party to any collective bargaining agreements. We maintain an at-will employment relationship with our employees, and have not entered into any contracts guaranteeing ongoing employment.

We believe that our employees give us a sustainable competitive advantage, and we understand the need to attract, retain and develop the best team possible. We believe the wage rates provided to our employees assist in retention of our top talent, and our compensation programs are integrated with our overall business strategies to incentivize performance and maximize shareholder returns. We offer a variety of programs that are designed to retain our employees and also provide opportunities to grow their professional careers while continuing to deliver value to the Company. Additionally, we maintain a comprehensive suite of benefits that provide our employees with various options including retirement, health and wellness, and life and disability plans.

We are committed to a highly-qualified workforce and we believe employees with different skillsets, experiences and interests drive superior results. This commitment extends to our hiring, development and promotion practices, which recognize our employees for their various capabilities and contributions to the Company.

We strive to promote a safe and healthy working environment, prioritizing the safety and well-being of our employees, contractors, the public, and the environment in the communities where we operate. Through frequent training sessions and monthly safety meetings, we equip our field employees with the knowledge and tools to mitigate risks and uphold our strong safety culture. While we have consistently excelled in health, safety, and environmental performance, maintaining an impressive record of minimal workplace incidents, we remain vigilant. Any workplace injury reinforces the need for ongoing safety awareness and enhanced protocols to prevent future occurrences.

Offices

Our principal executive offices are located at 300 N. Marienfeld Street, Suite 1000, Midland, Texas, 79701, and our telephone number is (432) 695-4222. We also have offices located in Carlsbad, New Mexico; Denver, Colorado; Eunice, New Mexico; Gardendale, Texas; Greenwood, Texas; Pecos, Texas; San Angelo, Texas; and Woodlands, Texas.

Available Information

Our internet website address is www.permianres.com. We routinely post important information for investors on our website. Within our website’s investor relations section, we make available free of charge 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 with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. Information on our website is not incorporated by reference into this Annual Report and should not be considered part of this document.

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

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors together with all of the other information included in this Annual Report and our other reports filed with the SEC before investing in our securities. The occurrence of one or more of these risks could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

Risks Related to Commodity Prices

Commodity prices are volatile, and a sustained period of low commodity prices for oil, NGLs and natural gas could adversely affect our business, financial condition and results of operations.

The prices we receive for our oil, NGLs and natural gas heavily influence our revenue, cash flows, profitability, access to capital, future rate of growth and carrying value of our properties. Oil, NGLs and natural gas are commodities, and their prices may fluctuate widely in response to relatively minor changes in the actual and expected supply of and demand for oil, NGLs and natural gas and market uncertainty. Historically, oil, NGL and natural gas prices have been volatile and subject to fluctuations relating to a variety of additional factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the global supply of and demand for oil, NGLs and natural gas;
- the price and quantity of foreign imports of oil, NGLs and natural gas;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Russia, Eastern Europe, Africa and South America, such as the recent developments in Venezuela;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- actions of U.S., European Union and other governments and governmental organizations relating to Russia's oil, NGLs and natural gas, including through sanctions, import restrictions and commodity price caps;
- actions of U.S. producers, and independent producers operating in other countries, relating to production levels;
- political, economic and other conditions that affect perceived or actual demand for oil, NGLs and natural gas, including international conflict, trade disputes, the imposition of tariffs or sanctions and global health concerns;
- the level of global exploration, development, production, and inventories;
- actions of U.S. and other governments to strategically release oil, NGLs and natural gas from strategic reserves, including any increased volumes of Venezuelan crude oil;
- the availability of refining and storage capacity;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters, including winter storms, hurricanes, droughts, fires, earthquakes, flooding and tornadoes;
- terrorist attacks and cybersecurity risks targeting oil and natural gas related facilities and infrastructure;
- technological advances, including AI and its increased use, affecting fuel economy, energy supply and energy consumption;
- the effect of energy conservation measures, alternative fuel requirements and the price and availability of alternative fuels;
- laws, regulations and taxes in the U.S. and in foreign jurisdictions that impact the demand for oil, NGLs and natural gas;
- shareholder activism or activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize emissions of carbon dioxide and methane GHGs or otherwise;
- localized and global supply and demand fundamentals; and
- expectations about future commodity prices.

These factors, among others, and the volatility of the energy markets make it extremely difficult to predict future oil, NGL and natural gas price movements with any certainty.

A sustained or extended decline in commodity prices may result in a shortfall in our expected revenues and cash flows and require us to reduce capital spending or borrow funds to cover any such shortfall. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods of low commodity prices for oil and natural gas and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone, moderate or eliminate our planned drilling and completions operations, or suspend production from current wells, which could result in the reduction of our expected production and some of our proved undeveloped reserves and related standardized measure. If we moderate or curtail our drilling, completion or production operations, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a sustained or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.

Accounting guidance requires that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. A sustained or extended decline in commodity prices could require that we recognize impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Risks Related to Our Reserves, Leases and Drilling Locations

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, seismic, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as commodity prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant inaccuracies in our interpretations of this technical data or in making our assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, commodity prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than our estimates and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

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 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. Our estimated proved reserves as of December 31, 2025, and related standardized measure were calculated under rules of the SEC using twelve-month trailing average benchmark prices of $66.01 per barrel of oil (WTI Posted) and $3.39 per MMBtu (Henry Hub spot), which may be substantially higher or lower than the available spot prices in 2025. For example, if the crude oil and natural gas prices used in our year-end reserve estimates were to increase or decrease by 10%, our proved reserve quantities at December 31, 2025 would increase by 45.5 MMBoe (4.1%) or decrease by 69.5 MMBoe (6.2%) and the pre-tax PV 10% of our proved reserves would increase by $2.2 billion (24%) or decrease by $2.2 billion (23%).

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flows and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production, particularly because competition in the oil and natural gas industry is intense, and many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of December 31, 2025, 29% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of December 31, 2025, over 96% of our total net acreage was held by production. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. Some of our leases also expire as to certain depths if continuous drilling obligations are not met. If our leases expire in whole or in part and we are unable to renew the leases, we will lose the right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

In the future, we may shut-in some or all of our production depending on market conditions, storage or transportation constraints and contractual obligations, and any prolonged shut-in of our wells could result in the expiration, in whole or in part, of the related leases, which could adversely affect our reserves, business, financial condition and results of operations.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, availability of gathering or transportation facilities, access to and availability of water sourcing and distribution systems, regulatory approvals, including permitting, and other factors. Because of these uncertain factors, we do not know if the numerous identified drilling locations will ever be drilled or if we will be able to produce natural gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Risks Related to Our Operations

Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, or at all, which could lead to a decline in our ability to access or grow production and reserves.

The oil and natural gas industry is capital-intensive. We make and expect to continue to make substantial capital expenditures related to development and acquisition projects. Historically, we have funded our capital expenditures with cash flows from operations and may from time to time utilize borrowings under OpCo’s revolving credit facility, proceeds from offering debt and equity securities and divestitures of non-core assets, and we intend to finance our future capital expenditures in a similar fashion. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, NGL and natural gas prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments.

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

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under OpCo's revolving credit facility and to access the capital markets.

If our revenues or the borrowing base under OpCo's revolving credit facility decrease as a result of lower oil, NGL and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under OpCo's revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties. This, in turn, could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Our future financial condition and results of operations will depend on the success of our development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. In addition to the risks we face in drilling for and producing oil and natural gas, some factors that may directly or indirectly negatively impact our scheduled operations include:

- lack of available gathering or transportation facilities or delays in constructing such facilities;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, qualified personnel, materials or resources;
- equipment failures, accidents or other unexpected operational events;
- delays imposed by or resulting from compliance with laws, regulations or litigation, including limitations resulting from wastewater disposal, emission of GHGs and limitations on hydraulic fracturing;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- natural disasters and other weather events;
- personal injuries and death;
- terrorist attacks and cybersecurity risks targeting oil and natural gas related facilities and infrastructure;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events, including those operating risks listed above, could materially and adversely affect our business, financial condition or results of operations. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which 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 toward 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 develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include:

- landing a wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation; and
- spacing the wells appropriately to maximize production rates and recoverable reserves.

Risks that we face while completing wells include:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to prevent unintentional communication with other wells.

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

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in certain portions of Texas and New Mexico in past years. These drought conditions have led some local water districts to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. Where practicable, we strive to use recycled water for our hydraulic fracturing operations. If we are unable to obtain water from water suppliers or our recycling operations, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

Our ability to produce crude oil, NGLs and natural gas economically and in commercial quantities could be impaired if we are unable to recycle or dispose of the produced water we produce in an economical and environmentally safe manner.

Our operations could be impaired if we are unable to recycle or dispose of the produced water we generate in an economical and environmentally safe manner. Where practicable, we strive to recycle produced water for our future oil and gas operations. Produced water that is not recycled is generally disposed in disposal wells that are operated by us or third-party contractors. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection of produced water resulting from oil and gas activities, which has led to increased public and governmental scrutiny of injection safety. For instance, in response to concerns regarding induced seismicity, regulators in Texas have adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely, or determined, to be causing seismic activity. Please refer to *Regulation of the Oil and Natural Gas Industry* in Part I, Items 1 and 2 of this Annual Report for further discussion regarding regulations affecting the handling and disposal of produced water.

Another potential consequence of produced water disposal activities and seismic events are lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. Such developments could result in additional regulation and restrictions on our use of injection wells or commercial disposal wells to dispose of produced water. Increased regulation and attention given to water disposal and induced seismicity could also lead to greater opposition, including litigation, to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in limitations on disposal well volumes, disposal rates and pressures or locations, require us or our vendors to shut down or curtail the injection into disposal wells, or cause delays, interruptions or termination of our operations, which events could have a material adverse effect on our business, financial condition and results of operations.

Our producing properties are concentrated in the Permian Basin, making us vulnerable to risks associated with operating in a single geographic area.

Our producing properties are geographically concentrated in West Texas and New Mexico in the Permian Basin. At December 31, 2025, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages, regional power outages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, NGLs or natural gas. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

The marketability of our production is dependent upon transportation and other facilities, most of which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.

The marketability of our oil, NGLs and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil, NGLs and natural gas production is generally transported from the wellhead by gathering systems that are either owned by us or third-party midstream companies. In general, we do not control the transportation of our production and our access to transportation facilities may be limited or denied. In some instances, we have contractual guarantees relating to the transportation of our production through firm transportation arrangements, but third-party systems may be temporarily unavailable due to pressure limitations, market conditions, mechanical failures, accidents or other reasons. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or third-party midstream companies or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGLs and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements, we may be required to shut in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, NGLs and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

We have entered into multi-year agreements with some of our suppliers, service providers and the purchasers of our oil and natural gas, which contain minimum volume commitments. Any failure by us to satisfy the minimum volume commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.

We have entered into certain multi-year supply and service agreements associated with energy and frac sand purchase agreements and have long-term agreements in place for drilling rigs, office rentals and other wellhead equipment. We also have various multi-year agreements that relate to the sale, transportation or gathering of our oil, NGLs and natural gas and may in the future enter into multi-year agreements for contracts for other services. Some of these agreements contain minimum volume commitments that we must satisfy or contractual penalties in the form of volume deficiencies or other remedies may apply. For example, we have recently entered into firm transportation arrangements where we are obligated to pay fixed amounts on minimum volumes regardless of actual volume throughput under these contracts. We may be unable to use our full transportation capacity under existing firm transportation agreements, resulting in obligations to pay fees without receiving revenues on sales. As of December 31, 2025, our aggregate long-term contractual obligation under our multi-year agreements was $1.5 billion, which represents the gross minimum obligation but does not include amounts that may be due under certain contracts that contain variable pricing or volumetric components as the future obligations cannot be determined. Further information about these agreements can be found at *Delivery Commitments* under Part I, Items 1 and 2 and *Note 13—Commitments and Contingencies* under Part II, Item 8 of this Annual Report. Any failure by us to satisfy the minimum volume commitments in these agreements could adversely affect our results of operations and financial position.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. In addition, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted by tariffs or other trade restrictions imposed by the United States on imported goods from countries where these goods are produced. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages or cost increases could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, NGL and natural gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased tariffs and comparative taxes. Such costs may rise faster than increases in our revenue as commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

We depend upon a small number of significant purchasers for the sale of most of our oil, NGL and natural gas production.

We normally sell production to a relatively small number of customers, as is customary in our business. See *Note 1—Basis of Presentation and Summary of Significant Accounting Policies* under Part II, Item 8 of this Annual Report for significant purchasers that accounted for more than 10% of our revenues for the years ended December 31, 2025, 2024 and 2023. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term.

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.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

We intend to pursue a strategy focused on both reinvestment and future acquisitions. As part of this strategy, we intend to make future acquisitions of assets or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future commodity prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Furthermore, no assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. In addition, debt agreements impose certain limitations on our ability to enter into mergers or combination transactions and our ability to incur certain indebtedness, which could indirectly limit our ability to engage in certain acquisition activities.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business, asset or property into our existing operations. The process of integrating acquired businesses, assets and properties may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Additionally, the integration of acquisitions is a complex, costly and time-consuming process, and our management may face significant challenges in such process. Some of the factors affecting integration will be outside of our control, and any one of them could result in increased costs and diversion of management's time and energy, and could materially and adversely affect our revenues.

We are heavily dependent on our information and operational technology systems and other digital technologies.

Our ability to effectively manage and operate our business depends significantly on information and operational technology systems and other digital technologies. The availability and integrity of these systems and technologies are essential for us to conduct our business and operations. Any failure of these systems to operate effectively and support our operations, challenge in transitioning to new upgraded or replacement systems, including any implementation or utilization of AI systems, difficulty in integrating systems and updates across our growing business, or a breach of these systems could materially and adversely impact the operations of our business. In addition, cybersecurity incidents, including deliberate attacks or unintentional events, have generally continued to increase in frequency and become increasingly sophisticated. The U.S. government has also issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats.

Any breach of our network may result in the loss of valuable business data or critical infrastructure, misappropriation of our customers', employees' or service providers' personal information, or a disruption of our business and operations, which could harm our customer relationships and reputation, and result in lost revenues, remediation and compliance costs, litigation, regulatory investigations and enforcements and penalties and fines. Although we utilize various procedures and controls to monitor, protect against and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing such threats from materializing, particularly given the unpredictability of the timing, nature, and scope of such breaches. While we endeavor to maintain insurance that covers certain cybersecurity incidents, we may not be insured for, or our insurance may be insufficient to protect us against, particular types of cybersecurity risks, and, in the future, such insurance may not continue to be available to us on reasonable terms, if at all. Furthermore, weaknesses in the cybersecurity of our vendors, suppliers, and other business partners could be used to facilitate an attack on our systems and networks.

Moreover, we must comply with increasingly evolving, complex and rigorous regulatory standards enacted to protect business and personal data. New laws and regulations governing data privacy and the unauthorized disclosure of personal or confidential information may pose compliance challenges and could elevate our costs. Any failure to comply with these laws and regulatory standards could subject us to legal and reputational risks. Misuse of or failure to secure personal information could also result in violation of data privacy laws and regulations, proceedings against us by governmental entities or others, damage to our reputation and credibility, and could have a negative impact on revenues and profits.

As of the date of this Annual Report, though the Company and its service providers have experienced certain cybersecurity incidents, we are not aware of any cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations and financial condition. However, we acknowledge that cybersecurity threats are continually evolving and the possibility of future cybersecurity incidents, material or otherwise, remains. Consequently, it is possible that any such occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations. Additional information on our cybersecurity risk management, strategy and governance can be found at Part I, Item 1C of this Annual Report.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our results of operations and financial condition.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us, particularly following recent consolidation within the industry. Many of our larger competitors not only drill for and produce oil and natural gas, but they also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. Our competitors 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 or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. Competition has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments, and acquiring resources and other materials in markets experiencing shortages. In addition, competition is strong for attractive oil and natural gas properties, oil and natural gas companies, and drilling rights. Our inability to compete effectively with our competitors could have a material and adverse impact on our business activities, financial condition and results of operations.

Risks Related to Our Derivative Transactions, Debt and Access to Capital

Our derivative activities could result in financial losses or could reduce our earnings.

We may enter into derivative instrument contracts for a portion of our oil and natural gas production from time to time. As of December 31, 2025, we had entered into derivative contracts covering a portion of our projected oil and gas production through 2027 (refer to *Note 8—Derivative Instruments* under Part II, Item 8 of this Annual Report for a summary of our derivative instruments as of December 31, 2025). Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of OpCo's borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile commodity prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

Since our production is not fully hedged, and we are also exposed to fluctuations in oil, NGL and natural gas prices as it relates to the price we receive from the sale of our unhedged volumes. We intend to continue to hedge a portion of our production, but we may not be able to do so at favorable prices. Accordingly, our revenues and cash flows are subject to increased volatility with regard to these unhedged volumes, and a decline in commodity prices could materially and adversely affect our business, financial condition and results of operations.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on our outstanding debt.

As of December 31, 2025, we had approximately $3.5 billion of total long-term debt and additional borrowing capacity of $2.5 billion under OpCo's revolving credit facility, all of which would be secured if borrowed. Subject to the restrictions in the instruments governing OpCo's outstanding indebtedness (including OpCo's revolving credit facility and senior notes), OpCo and its subsidiaries may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the instruments governing OpCo's outstanding indebtedness do contain restrictions on the incurrence of additional indebtedness, these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

Our current and future level of indebtedness could affect our operations in several ways, including the following:

- require 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;
- limit management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- make it more likely that a reduction in OpCo's borrowing base following a periodic redetermination could require OpCo to repay a portion of its then-outstanding bank borrowings;

- make us vulnerable to increases in interest rates as the indebtedness under OpCo’s revolving credit facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to our competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for OpCo to satisfy its obligations under its debt and increase the risk that we may default on its debt obligations.

We may not be able to generate sufficient cash to service all of OpCo’s indebtedness and may be forced to take other actions to satisfy OpCo’s obligations under applicable debt instruments, which may not be successful.

OpCo’s ability to make scheduled payments on or to refinance its indebtedness depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit OpCo to pay the principal, premium, if any, and interest on OpCo’s indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance OpCo’s indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require OpCo to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm OpCo’s ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. The agreements governing OpCo’s indebtedness restrict OpCo’s ability to dispose of assets and OpCo’s use of the proceeds from such disposition. OpCo may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit OpCo to meet scheduled debt service obligations.

Restrictions in OpCo’s existing and future debt agreements could limit our growth and ability to engage in certain activities.

OpCo’s credit agreement with a syndicate of banks that provides for a secured revolving credit facility, maturing in February 2028 (the “Credit Agreement”), and the indentures governing its senior notes contain a number of significant covenants, including restrictive covenants that may limit OpCo’s ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- make certain payments;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

These restrictions may be suspended when our debt instruments are assigned an investment grade rating (Baa3 or better by Moody’s Investors Service, Inc. or BBB- or better by S&P Global Ratings or Fitch Ratings Inc., or two out of three, as applicable). However, there can be no assurance that we will be able to achieve such ratings.

In addition, OpCo’s Credit Agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of December 31, 2025, we were in full compliance with such financial ratios and covenants.

The restrictions in OpCo’s debt agreements may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictions impose on OpCo.

If OpCo is unable to comply with the restrictions and covenants in the agreements governing its indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that OpCo has borrowed.

Any default under the agreements governing OpCo's indebtedness that is not cured or waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make OpCo unable to pay principal, premium, if any, and interest on such indebtedness. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on OpCo's indebtedness, or if OpCo otherwise fails to comply with the various covenants, including financial and operating covenants, in the agreements governing OpCo's indebtedness, OpCo could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under OpCo's revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under OpCo's revolving credit facility to avoid OpCo being in default. If OpCo breaches the covenants under its revolving credit facility and seeks a waiver, OpCo may not be able to obtain a waiver from the required lenders. If this occurs, OpCo would be in default under the revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

Any significant reduction in the borrowing base under OpCo's revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

OpCo's revolving credit facility limits the amounts OpCo can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually in the spring and fall. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the loan. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of permitted senior unsecured notes OpCo may issue in the future. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under OpCo's revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. The elected commitments are currently $2.5 billion.

In the future, we may not be able to access adequate funding under OpCo's revolving credit facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, OpCo could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service OpCo's indebtedness.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financing and trade credit and the terms of any financing or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates, as a result of elevated rates of inflation or otherwise, or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets, due to the imposition, or threat, of tariffs and other trade restrictions, geopolitical conflicts, including in oil producing countries like Venezuela, or otherwise, may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Risks Related to Legislative and Regulatory Initiatives

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA and other federal agencies have asserted regulatory authority over aspects of the process. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The CEQ is coordinating an administration-wide review of hydraulic fracturing practices. Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above-and-below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. To date, EPA has taken no further action in response to the December 2016 report. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These completed, ongoing, or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms. Additionally, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, the Railroad Commission of Texas (the "TRRC") has issued rules that set the requirements for drilling, putting pipe down and cementing wells, testing and reporting obligations, and the disclosure of substances used in the hydraulic fracturing process. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. State and federal regulatory agencies, including Texas, have also recently focused on a possible connection between the operation of injection wells used for natural gas and oil waste disposal and seismic activity. The TRRC has issued orders restricting the use of disposal wells it determined were likely influencing seismic activity. Separately, New Mexico has implemented protocols requiring operators to take various actions with respect to disposal wells within a specified proximity of recent seismic activity, including a requirement to limit injection rates if the seismic event in question reached a certain magnitude. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, production or development activities utilizing hydraulic fracturing or injection wells for waste disposal, which could indirectly impact our business, financial condition and results of operations. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Conservation measures, technological advances and any negative shift in market perception toward the oil and natural gas industry could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, any increase in consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. Additionally, the increased competitiveness of alternative energy sources (such as electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Certain segments of the investor community have previously expressed negative sentiment towards investing in the oil and natural gas industry and some financial institutions have previously developed investment funds that expressly exclude fossil fuel and other carbon-intensive businesses based on social and environmental considerations. Furthermore, certain other stakeholders have previously pressured commercial and investment banks to stop funding oil and gas projects.

The impact of the changing demand for oil and natural gas, together with any change in investor or consumer sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent, complex and evolving federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations or otherwise relating to protection of the environment and natural resources (including threatened and endangered species and their habitats). These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the requirement to engage in remedial measures to prevent or mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands 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. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental, health and safety risks and costs or may not provide sufficient coverage if an environmental, health and safety claim is made against us. Moreover, public interest in the protection of the environment and human health has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. In the states of New Mexico and Texas, as an example, governmental authorities are investigating the practice of flaring natural gas and it is possible that such states could implement additional volumetric or other restrictions on this practice which may require us to curtail or shut in production which otherwise is or would be flared due to the unavailability of acceptable delivery, transportation or processing arrangements. 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. Please refer to *Regulation of the Oil and Natural Gas Industry* in Part I, Items 1 and 2 of this Annual Report for further discussion on the topics referenced above and additional information on existing and proposed laws and regulations related to environmental and occupational health and safety matters.

Climate change laws and regulations restricting emissions of GHGs could increase our costs and reduce demand for the oil and natural gas we produce.

The threat of climate change continues to attract attention in the United States and around the world. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor, limit, and report existing emissions of GHGs as well as to reduce such future emissions. While no comprehensive climate change legislation has been implemented at the federal level, certain federal laws, like the IRA, have been enacted to advance numerous climate-related objectives. The OBBBA rescinds or eliminates funding for multiple programs under the IRA aimed at reducing or monitoring GHG emissions and other air pollutants, such as the Greenhouse Gas Reduction Fund and methane monitoring initiatives. While the OBBBA will potentially affect federal efforts to address climate change and emissions reductions, various federal agencies have, from time to time, adopted climate change considerations into their rulemaking and decision-making processes and have promulgated regulations that seek to restrict, monitor, or otherwise limit GHG emissions. International climate commitments made by political, industrial, and financial and other stakeholders may also impact commercial, regulatory, and consumer trends related to climate change.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the CAA that, among other things, require PSD preconstruction and Title V operating permits for GHG emissions from certain large stationary sources, mandate monitoring and annual reporting of GHG emissions, and impose new standards for reducing methane emissions from oil and gas operations by limiting venting and flaring and implementing leak detection and repair programs. Federal policy towards GHG emissions, and regulation thereunder, has varied significantly between the past several Presidential administrations. The current Trump administration has expressed a policy preference of limiting or rescinding regulations concerning GHG emissions and, in February 2026, promulgated a final rule repealing the EPA’s 2009 “Endangerment Finding” and its motor vehicle GHG emission performance standards. This rescission of the “Endangerment Finding” eliminates the basis for EPA’s authority under the CAA for most of its regulations concerning GHGs. However, whether or how such policies and the EPA’s recission of its “Endangerment Finding” will be implemented and if they will survive any potential legal challenges, or whether future administrations or Congress may pursue new GHG emissions regulation, cannot be predicted at this time.

At the international level, the United Nations-sponsored Paris Agreement encourages nations to limit their GHG emissions through nationally-determined, though non-binding, reduction goals. Recent Conferences of the Parties have resulted in reaffirmations of the objectives of the Paris Agreement, calls for parties to eliminate certain fossil fuel subsidies and pursue reductions in non-carbon dioxide GHG emissions, agreements to transition away from fossil fuels in energy systems and increase renewable energy capacity, financial commitments to fund energy transition efforts in developing countries, and similar initiatives, though none legally binding. However, in January 2025, President Trump ordered the revocation of any United States financial commitments on emission goals associated with international climate agreements. Then, in January 2026, the United States finalized its withdrawal from the Paris Agreement. The impacts of the United States’ withdrawal and other existing or future climate-related orders, pledges, agreements or any legislation or regulation promulgated in connection with the Paris Agreement, the Global Methane Pledge, or other international conventions cannot be predicted at this time. Further, state and local governments, financial institutions, and industry groups may elect to continue participating in international climate-related initiatives.

Please refer to *Regulation of the Oil and Natural Gas Industry* in Part I, Items 1 and 2 of this Annual Report for further discussion on the topics referenced above and additional information on existing and proposed laws, regulations and international initiatives intended to address GHGs and other climate change issues. Existing and future laws and regulations relating to climate change and GHG emissions could increase our costs, reduce demand for our products, limit our growth opportunities, impair our ability to develop our reserves and have other adverse effects on our business. Climate change concerns could impact our stock price and access to capital to the extent certain stockholders, bondholders, and institutional lenders who elect to shift their investments to less carbon-intensive industries. While the landscape is evolving, certain U.S. and international banks, insurers or other financial institutions have also made “net zero” emission commitments or signed-on to initiatives related to reducing GHG emissions. Any reduction in the availability of capital or access to insurance products for us or our customers and suppliers could adversely impact our operations and financial performance.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered or threatened species and their habitats could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves. Please refer to *Regulation of the Oil and Natural Gas Industry* in Part I, Items 1 and 2 of this Annual Report for further discussion on protected species regulations and developments.

A negative shift in investor sentiment towards the oil and natural gas industry and increased attention to sustainability and conservation matters may adversely impact our business.

Increased attention from companies’ investors, customers, employees, regulatory bodies and other stakeholders, as well as natural capital and societal expectations, on companies to address climate change, investor and societal expectations regarding voluntary or mandatory sustainability initiatives and disclosures, and consumer demand for alternative sources of energy may result in increased costs (including but not limited to increased costs associated with compliance, stakeholder engagement, contracting, and insurance), reduced demand for our products and services, reduced profits, increased legislative and judicial scrutiny, investigations and litigation, heightened scrutiny of our statements and initiatives, and negative impacts on our stock price and access to capital markets. Increased attention to climate change and environmental conservation, for example, may result in demand shifts for our products and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that liability could be imposed on us without regard to our causation of or contribution to the asserted damage, or to other mitigating factors. Voluntary disclosures regarding sustainability matters, as well as any sustainability disclosures mandated by law, could result in private litigation or government investigation or enforcement action regarding the sufficiency or validity of such disclosures. In addition, failure or a perception (whether or not valid) of failure to pursue, implement or make progress against sustainability strategies or achieve sustainability goals or commitments, including any GHG reduction or neutralization goals or commitments, could result in governmental investigations or enforcement, private litigation and damage our reputation, cause our investors or consumers to lose confidence in our Company, and negatively impact our operations.

Any restrictions on oil and natural gas development on federal lands have the potential to adversely impact our operations.

We possess leases which are granted by the federal government and administered by the BLM, a federal agency. Operations we conduct on federal leases must comply with numerous additional statutory and regulatory restrictions. These leases contain relatively standardized terms requiring compliance with detailed regulations. Under certain circumstances, the BLM may require operations on federal leases to be suspended or terminated. Any such suspension or termination of our leases could adversely impact the results of our operations.

Federal leasing and permitting programs for oil and natural gas development on federal lands have been, from time to time, subject to suspension or cancellation by executive order, subject to litigation by third parties, or otherwise restricted by federal action. For example, previous Presidential administrations have issued moratoriums on oil and gas leasing. Additionally, in 2024, the BLM finalized a rule requiring operators to limit venting and flaring and pay royalties on lost gas, though this rule is currently subject to litigation, postponed implementation, and reconsideration by the Trump administration. Congress may also, from time to time, legislate changes to the fiscal terms and environmental performance obligations of federal oil and gas leases. Certain lawmakers have proposed, and may continue to propose, to reduce or ban further leasing on federal lands or to adopt further restrictions on oil and gas development on federal lands. While we cannot predict the ultimate impact of these changes or whether federal agencies will implement further reforms, any revisions to the federal leasing or permitting process, by executive action, legislation or regulation, that make it more difficult or costly for us to pursue operations on federal lands may adversely impact our operations. However, any such adverse developments are expected to have no more than a minimal impact on our results, given our limited exposure of leases on federal lands. Additionally, any additional actions the Trump administration will take with respect to oil and gas leasing on federal lands cannot be predicted at this time, though any such actions may be subject to litigation. Please refer to *Regulation of the Oil and Natural Gas Industry* in Part I, Items 1 and 2 of this Annual Report for further discussion of the regulations affecting our operations on federal lands.

Changes in tax laws or regulations or the interpretation thereof or the imposition of new or increased taxes may increase our future tax liabilities, which could adversely affect our business, results of operation, financial condition and cash flows.

From time to time, U.S. federal and state level legislation has been proposed that, if enacted into law, would make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently applicable to natural gas and oil exploration and development companies. It is unclear whether any such changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any such legislation or other changes in U.S. federal or state tax laws or the imposition of new or increased taxes or fees on natural gas and oil extraction could increase our future tax liabilities, which could adversely affect our business, results of operations, financial condition and cash flows.

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NYSE. In particular, we are required to comply with certain SEC, NYSE and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time, including as a result of new policies and priorities by the Trump administration, and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

Risks Related to Our Common Stock and Capital Structure

Our cash flow is dependent upon the ability of our operating subsidiaries to make cash distributions to us, the amount of which will depend on various factors.

We are a holding company and have no material assets other than our equity interest in OpCo, and we do not have any independent means of generating revenue. The amount of cash that our operating subsidiaries can distribute each quarter principally depends upon the amount of cash generated from operations, which may fluctuate from quarter to quarter based on, among other things:

- the amount of oil and natural gas our operating subsidiaries produce from existing wells;
- market prices of oil, NGLs and natural gas;
- any restrictions on the payment of distributions contained in covenants in OpCo's revolving credit facility;
- our operating subsidiaries' ability to fund their drilling and development plans;
- the levels of investments in each of our operating subsidiaries, which may be limited and disparate;
- the levels of operating expenses, maintenance expenses and general and administrative expenses;
- regulatory action affecting the supply of, or demand for, oil, NGLs and natural gas, and operating costs and operating flexibility;

- prevailing economic conditions; and
- adverse weather conditions and natural disasters.

To the extent that we need funds and OpCo or its subsidiaries are restricted from making such distributions or payments under applicable law or regulation or under the terms of any current or future indebtedness agreements or the Eighth Amended and Restated Limited Liability Company Agreement of OpCo, or are otherwise unable to provide such funds, our liquidity and financial condition could be materially adversely affected.

Moreover, because we have no independent means of generating revenue, our ability to make tax payments and fund our other obligations is dependent on the ability of OpCo to make distributions to us in an amount sufficient to cover our tax and other applicable obligations. This ability, in turn, may depend on the ability of OpCo's subsidiaries to make distributions to it. The ability of OpCo, its subsidiaries and other entities in which it directly or indirectly holds an equity interest to make such distributions will be subject to, among other things, (i) the applicable provisions of Delaware law (or other applicable jurisdiction) that may limit the amount of funds available for distribution and (ii) restrictions in relevant debt instruments issued by OpCo or its subsidiaries and other entities in which it directly or indirectly holds an equity interest.

If we experience any material weakness or otherwise fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, stockholders could lose confidence in our financial reporting, which would harm our business and the value of our Class A Common Stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which includes furnishing a report by management on, among other things, the effectiveness of our internal controls and whether management has identified any material weaknesses therein. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the value of our Class A Common Stock.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional shares of common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market, or the perception that these sales could occur, could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

The declaration of dividends and any repurchases of our common stock are each within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.

Dividends, whether fixed or variable, and stock repurchases are authorized and determined by our board of directors in its sole discretion and depend upon a number of factors, including the Company's financial results, cash requirements and future prospects, restrictions in our debt agreements, as well as such other factors deemed relevant by our board of directors. In 2024, our board of directors authorized a stock repurchase program to acquire up to $1 billion of our outstanding common stock, which replaced our previous $500 million stock repurchase program. However, this stock repurchase program may be suspended from time to time, modified, extended or discontinued by our board of directors at any time. Similarly, any dividends, whether fixed or variable, we may declare in the future will be determined by our board of directors in its sole discretion. Any elimination of, or downward revision in, our stock repurchase program or dividend policy could have an adverse effect on the market price of our common stock.

Provisions contained in our Charter and Bylaws, as well as provisions of Delaware law, could impair a takeover attempt, which may adversely affect the market price of our common stock.

Our Amended and Restated Certificate of Incorporation (as amended and restated, the "Charter") and Second Amended and Restated Bylaws (as amended and restated, the "Bylaws") contain provisions that could have the effect of delaying or preventing changes in control or changes in our management without the consent of our board of directors. These provisions include:

- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;
- the exclusive right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director, which prevents stockholders from being able to fill vacancies on our board of directors;
- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;
- a prohibition on stockholder action by written consent, which forces stockholder action to be taken at an annual or special meeting of our stockholders;
- the requirement that a special meeting of stockholders may be called only by the chairman of the board of directors, the chief executive officers, or the board of directors pursuant to a resolution adopted by a majority of the board of directors, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;
- limiting the liability of, and providing indemnification to, our directors and officers;
- controlling the procedures for the conduct and scheduling of stockholder meetings;
- providing that directors may be removed prior to the expiration of their terms by stockholders only for cause; and
- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

These provisions, alone or together, could delay hostile takeovers and changes in control of the Company or changes in our board of directors and management.

As a Delaware corporation, we are also subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law, which prevents some stockholders holding more than 15% of our outstanding voting common stock from engaging in certain business combinations without approval of the holders of substantially all of our outstanding voting common stock. Any provision of our Charter or Bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their securities and could also affect the price that some investors are willing to pay for our securities.

The Charter designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for substantially all actions and proceedings that may be initiated by stockholders, which could limit shareholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our Charter provides that, unless we consent in writing to the selection of an alternative forum, the (i) Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (A) any derivative action or proceeding brought on our behalf, (B) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our shareholders, (C) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, the Charter or our Bylaws or (D) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein; and (ii) subject to the foregoing, the federal district courts of the United States of America shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act, including all causes of action asserted against any defendant to such complaint. In the event the Delaware Court of Chancery lacks subject matter jurisdiction, then the sole and exclusive forum for such action or proceeding shall be the federal district court for the District of Delaware.

Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our shareholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect its business, financial condition, prospects, or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

We rely on information and operational technology and data to operate our business effectively and recognize the importance of implementing and maintaining cybersecurity systems and processes that allow us to protect the confidentiality, integrity and availability of our information and operational systems and the data residing within them.

In order to monitor our information and operational technology systems and data and to identify, assess and manage potential threats to such, we maintain a cybersecurity risk assessment and management program (the "Cybersecurity Program"). We employ a variety of tools designed to identify, assess and manage cybersecurity threats, including monitoring and detection programs, network security measures, firewall monitoring devices and encryption of certain data. The Cybersecurity Program includes a cybersecurity incident response plan that provides the framework for categorizing and responding to cybersecurity incidents. As part of our cybersecurity risk management process, we conduct simulated cybersecurity incidents to ensure that we are prepared to respond to such incidents and to highlight any areas for potential improvement in our cyber incident preparedness.

The Cybersecurity Program is maintained in alignment with the National Institute of Standards and Technology (NIST) Cybersecurity Framework for risk management. The Company aims to conduct bi-annual NIST cybersecurity risk assessments and annual independent penetration tests to identify potential areas for enhancement and to evaluate the Cybersecurity Program's maturity relative to peer organizations, industry benchmarks, and other applicable standards. Our cybersecurity risk management processes are integrated into our broader risk management program.

Cybersecurity incidents are evaluated by the cybersecurity team, which reports to our Vice President and Chief Information Officer ("CIO"). If an incident is determined to constitute a breach, it is elevated to our legal department and management for further review, including whether the matter requires notification to the Audit Committee or the Board of Directors or disclosure to investors through a public filing.

Governance

Our cybersecurity risk assessment and management is primarily the responsibility of our CIO, who is supported by the information technology teams he leads including the cybersecurity team and certain assessor, consultants, auditors or other third parties, as necessary. Our CIO has over 25 years of industry experience in the field of information systems, including information security and risk management. He oversees our risk assessment programs, remediation of known risks, processes for the regular monitoring of our information systems and our employee cybersecurity training programs. Our Board of Directors also oversees cybersecurity risks through our Audit Committee, which receives and assesses periodic reports and updates regarding our Cybersecurity Program from management and our CIO.

Impact of Risks from Cybersecurity Threats

As of the date of this report, though the Company and its service providers have experienced certain cybersecurity incidents, we are not aware of any previous cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations and financial condition. We acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents, material or otherwise, remains. Despite the implementation of our Cybersecurity Program, our security measures cannot guarantee that a significant cybersecurity incident will not occur. While we devote resources to our security measures designed to protect our systems and information, no security measure is infallible. For more information about the cybersecurity risks we face, refer to *Risk Factors* under Part I, Item 1A of this Annual Report.

ITEM 3. LEGAL PROCEEDINGS

Refer to *Note 13—Commitments and Contingencies* under Part II, Item 8 of this Annual Report for more information regarding our legal proceedings.

Environmental. Due to the nature of the oil and gas industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination and we conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from events are probable and the costs can be reasonably estimated. Item 103 of Regulation S-K promulgated under the Exchange Act requires disclosure regarding certain proceedings arising under federal, state or local environmental laws when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that the Company reasonably believes will exceed a specified threshold. Pursuant to such item, we have elected to use a $1 million threshold for purposes of determining whether disclosure of any such proceedings is required. We believe proceedings under this threshold are not material to our business and financial condition.

In connection with the Earthstone Merger, we assumed a liability related to potential environmental defects that were identified through diligence reviews associated with Earthstone's previous acquisition of Novo Oil & Gas Legacy Holdings, LLC, Novo Intermediate, LLC and Novo Oil & Gas Holdings, LLC (collectively "Novo"). We have received a Tolling Agreement for Novo's alleged violations but have not yet received a Notice of Violation ("NOV"). At this time, these violations are expected to result in a penalty that will be finalized upon issuance of the NOV; while the Company cannot predict the ultimate outcome of this matter, the potential for penalties or settlement costs could exceed $1 million. The Company does not believe that this matter will have a material adverse effect on its business, financial position, results of operations, or cash flows.

We are not aware of any other material environmental claims existing as of December 31, 2025 over our threshold which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws or other environmental liabilities will not be discovered on our properties.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

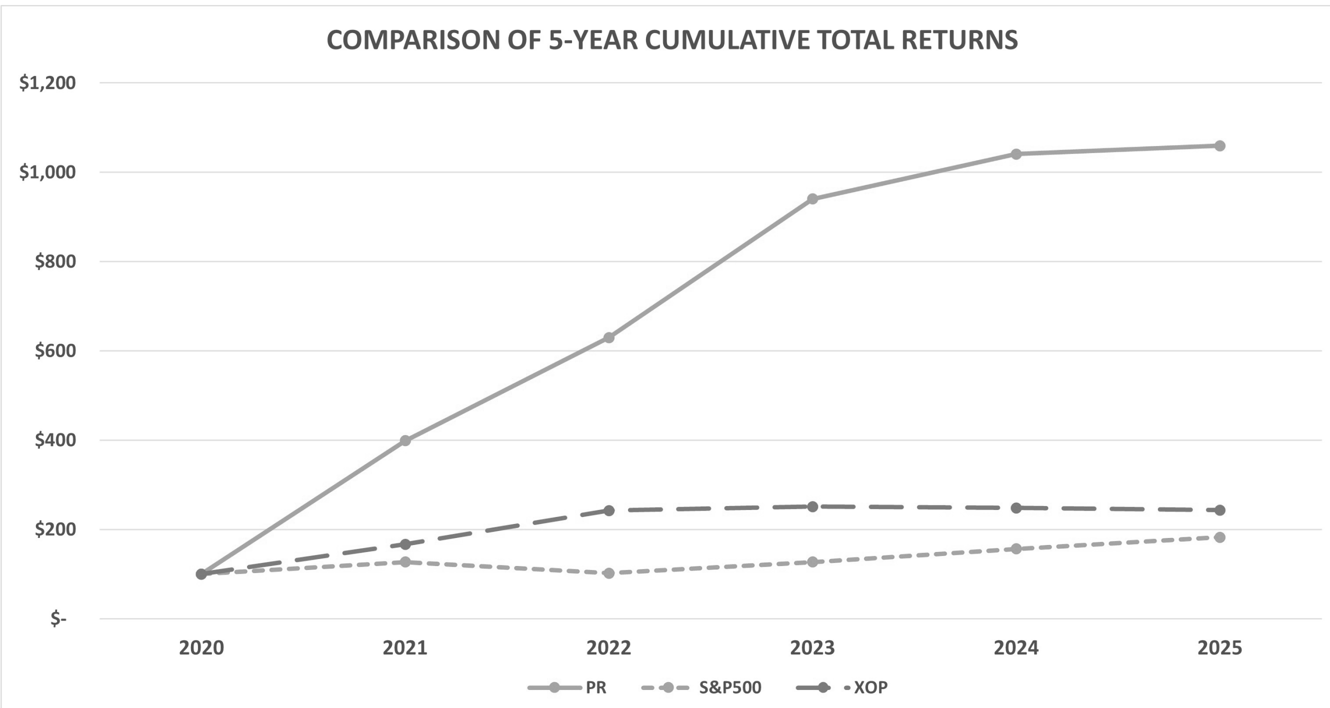
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

Our Class A Common Stock is currently listed on the New York Stock Exchange under the ticker symbol "PR". As of February 20, 2026, there were 264 registered holders of record of our Class A Common Stock and 4 registered holders of record of our Class C Common Stock.

Stock Performance Graph

The performance graph below compares the cumulative total stockholder return on our Class A Common Stock ("PR") to that of the Standard & Poor's 500 Index ("S&P 500") and the Standard & Poor's 500 Oil and Gas Exploration & Production ETF ("XOP"). The "cumulative total return" assumes $100, including reinvestment of any dividends, was invested in our Class A Common Stock, the S&P 500, and XOP on December 31, 2020, and tracks it through December 31, 2025. The results shown in the graph below are not necessarily indicative of future stock price performance. The following performance graph and related information shall be deemed to be furnished, but not filed with the SEC.



Dividend Policy

We plan to return capital to shareholders through a combination of base dividends and opportunistic share repurchases. Our quarterly base dividend was set at $0.15 per share ($0.60 annually) during the year ended December 31, 2025, and was increased to $0.16 per share ($0.64 annually) for the year ended December 31, 2026. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board of Directors. Our Board of Directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the Board deems relevant at the time of such determination.

Stock Repurchase Program

Our Board of Directors has authorized a share repurchase program of $1 billion of the Company's outstanding Common Stock ("Repurchase Program"), which is approved to run on an indefinite basis and can be used by the Company to reduce its shares of Class A and Class C Common Stock outstanding. As of December 31, 2025, we have approximately $926.3 million available under the Repurchase Program. During the three months ended December 31, 2025, we did not repurchase any Common Stock in the open market under our Repurchase Program.

ITEM 6. [Reserved]

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" in this Annual Report. The following discussion and analysis contain 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 include, but are not limited to, future market prices for oil, NGLs and natural gas, future production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, inflation, regulatory changes, and other uncertainties, as well as those factors discussed in "Cautionary Statement Concerning Forward-Looking Statements" and "Item 1A. Risk Factors" in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may or may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

We are an independent oil and natural gas company focused on driving returns to our stockholders through the acquisition, optimization and development of high-return oil and natural gas properties. Our assets and operations are located in the Permian Basin, with a concentration in the core of the Delaware Basin. Our principal business objective is to increase shareholder value by efficiently developing our oil and natural gas assets, with an overall objective of improving our rates of return and generating sustainable free cash flow.

Market Conditions

Our revenue, profitability and ability to return cash to stockholders can depend substantially on factors beyond our control, such as economic, political and regulatory developments. Prices for crude oil, NGLs and natural gas have experienced significant fluctuations in recent years and may continue to fluctuate widely in the future.

Concerns regarding global economic growth, elevated interest rates, inflation, increases in global oil supply, tariffs and international trade policies have resulted in lower oil prices over the past year. Despite recent geopolitical tensions and strong global demand, higher than anticipated supply increases from OPEC and their potential impact to global inventories resulted in further downward pressure on prices through the end of 2025.

Throughout 2024 and 2025, natural gas prices in the Permian Basin were negatively impacted by low demand as a result of pipeline capacity constraints out of the basin, pipeline maintenance, and higher production levels. These factors have led to lower or, during certain periods, negative regional gas prices being realized for natural gas sales at the Waha hub in West Texas resulting in lower gas realizations on our production sold at these regional price points.

The oil and natural gas industry is cyclical, and it is likely that commodity prices, as well as commodity price differentials, will continue to be volatile due to fluctuations in global supply and demand, inventory levels, geopolitical events, federal and state government regulations weather conditions, growth in alternative energy sources, supply chain constraints and other factors. The following table highlights the quarterly average price trends for NYMEX WTI spot prices for crude oil and NYMEX Henry Hub index price for natural gas since the first quarter of 2023:

	2023				2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude Oil (per Bbl)	$76.13	$73.78	$82.26	$78.32	$76.96	$80.55	$75.16	$70.28	$71.42	$63.71	$64.95	$59.13
Natural Gas (per MMBtu)	$2.67	$2.12	$2.58	$2.74	$2.41	$2.04	$2.08	$2.42	$4.27	$3.16	$3.07	$3.69

Lower commodity prices and lower futures curves for oil and gas prices can result in impairments of our proved oil and natural gas properties or undeveloped acreage and may materially and adversely affect our operating cash flows, liquidity, financial condition, results of operations, future business and operations, and/or our ability to finance planned capital expenditures, which could in turn impact our ability to comply with covenants under our Credit Agreement and senior notes. Lower realized prices may also reduce the borrowing base under our Credit Agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to such lenders. Upon a redetermination, if any borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under the Credit Agreement.

Due to the cyclical nature of the oil and gas industry, fluctuating demand for oilfield goods and services can put pressure on the pricing structure within our industry. The cost of oilfield goods and services are closely linked to commodity price trends, rising when prices increase and decreasing when prices fall. In addition, the U.S. saw higher levels of inflation during 2024 and 2025 due to concerns over international conflicts, tariffs and trade policies. Inflationary pressures such as these may also result in increases to the costs of our oilfield goods, services and personnel, which can in turn cause our capital expenditures and operating costs to rise.

2025 Highlights and Future Considerations

2025 Bolt-On Acquisitions

On June 16, 2025, we completed an acquisition of approximately 13,000 net leasehold acres with Apache Corporation for an unadjusted purchase price of $608 million. The acreage acquired is predominately located directly offsetting our existing asset position in the core of our New Mexico operating area.

Additionally, during the year ended December 31, 2025, we completed multiple acquisitions of oil and natural gas properties for a cumulative adjusted purchase price of approximately $471.1 million. These acquisitions are part of our ongoing bolt-on and grassroots acquisition programs.

Return of Capital Program

During the year ended December 31, 2025, we declared and paid quarterly base dividends totaling $0.60 per share of Class A Common Stock and distributions totaling $0.60 per share of Class C Common Stock (each of which has an underlying common unit of OpCo ("Common Units")). The cash dividends and distributions paid totaled $502.9 million for the year ended December 31, 2025.

During the year ended December 31, 2025, we paid a total of $73.7 million to repurchase 4.4 million shares of our Class A Common Stock and 2.0 million Class C Common Stock at a weighted average price of $11.57 per share as part of our Repurchase Program. The shares that were repurchased were subsequently canceled.

Financing

During September 2025, we completed the redemption of all of our outstanding 3.25% senior unsecured convertible notes due 2028 (the "Convertible Senior Notes") for a combination of shares of Class A Common Stock and cash (the "Redemption"). The Redemption resulted in the issuance of 30.6 million shares of our Class A Common Stock at a 179.9208 conversion rate per $1,000 principal amount of the Convertible Senior Notes as well as a cash payment of $0.1 million.

During June 2025, we repurchased $2.7 million of our senior notes due 2026 (the "2026 Senior Notes") at a price equal to 99.7% of the principal amount paid plus accrued and unpaid interest up to, but excluding, the repurchase date. Subsequently, during September 2025, we redeemed all remaining 2026 Senior Notes at a price equal to 100% of the aggregate principal amount outstanding of $286.7 million plus accrued and unpaid interest up to, but excluding, the redemption date.

During January 2025, we redeemed $175 million of our senior notes due 2031 (the "2031 Senior Notes") at a redemption price equal to 109.875% of the aggregate principal amount redeemed plus accrued and unpaid interest up to, but excluding, the redemption date. Following the redemption, the remaining aggregate principal amount of the 2031 Senior Notes outstanding was $325 million.

Corporation Reorganization

On January 7, 2026, we completed a corporate reorganization pursuant to which we, among other things, reorganized under a new public holding company (the "Reorganization"). In connection with the Reorganization, the public holding company prior to the Reorganization became a wholly owned subsidiary of the new public holding company, which, following completion of the Reorganization, changed its name to "Permian Resources Corporation," became the successor issuer of the prior public holding company and replaced the prior public holding company, with its shares of Class A Common Stock continuing to trade on the NYSE on an uninterrupted basis.

In connection with the Reorganization, certain holders of our Class C Common Stock exchanged all of their Common Units for Class A Common Stock on a one-for-one basis (and their corresponding shares of Class C Common Stock were cancelled for no consideration). This resulted in approximately 35.5 million shares of Class C Common Stock remaining outstanding, reducing the noncontrolling interest ownership of OpCo to approximately 4% immediately following the Reorganization. Refer to *Note 16 —Subsequent Events* under Part II, Item 8 of this Annual Report for additional information on the Reorganization that occurred after the reporting period.

Results of Operations

For the Year Ended December 31, 2025 Compared to the Year Ended December 31, 2024

The following table provides the components of our net revenues and net production (net of all royalties, overriding royalties and production due to others) for the periods indicated, as well as each period's average prices and average daily production volumes:

	Year Ended December 31,		Increase/(Decrease)	
	2025	2024	$	%
Net revenues (in thousands):				
Oil sales	$ 4,251,193	$ 4,362,965	$ (111,772)	(3)%
NGL sales	658,515	637,529	20,986	3 %
Natural gas sales	131,663	240	131,423	54,760 %
Purchased gas sales, net	23,840	—	23,840	100 %
Oil and gas sales	$ 5,065,211	$ 5,000,734	$ 64,477	1 %
Net production:				
Oil (MBbls)	66,364	58,276	8,088	14 %
NGL (MBbls)	35,773	30,636	5,137	17 %
Natural gas (MMcf)	247,045	220,900	26,145	12 %
Total (MBoe)[3]	143,311	125,730	17,581	14 %
Average daily net production:				
Oil (Bbls/d)	181,819	159,225	22,594	14 %
NGL (Bbls/d)	98,008	83,706	14,302	17 %
Natural gas (Mcf/d)	676,835	603,551	73,284	12 %
Total (Boe/d)[3]	392,633	343,523	49,110	14 %
Average sales prices:				
Oil (per Bbl)	$ 64.06	$ 74.87	$ (10.81)	(14)%
Effect of derivative settlements on average price (per Bbl)	2.40	0.03	2.37	7,900 %
Oil including the effects of hedging (per Bbl)	$ 66.46	$ 74.90	$ (8.44)	(11)%
NGL (per Bbl)	$ 18.41	$ 20.81	$ (2.40)	(12)%
Natural gas (per Mcf)	$ 0.53	$ —	$ 0.53	100 %
Effect of derivative settlements on average price (per Mcf)	0.48	0.34	0.14	41 %
Effect of purchased gas sales on average price (per Mcf)	0.10	—	0.10	100 %
Natural gas including the effects of hedging (per Mcf)	$ 1.11	$ 0.34	$ 0.77	226 %

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Oil, NGL and Natural Gas Sales Revenues. Total net revenues for the year ended December 31, 2025 increased by $64.5 million, or 1%, compared to the year ended December 31, 2024. Revenues are a function of oil, NGL and natural gas volumes sold and average commodity prices realized.

Net production volumes for oil, NGLs and natural gas increased 14%, 17% and 12%, respectively, between periods. The increase in oil production resulted from additional production added from wells placed online or acquired since the fourth quarter of 2024. These oil volume increases were partially offset by normal production declines across our existing wells. NGLs and natural gas are produced concurrently with our crude oil volumes, which typically result in a high correlation between fluctuations in oil quantities sold and NGL and natural gas quantities sold, driving the respective 17% and 12% increases in NGL and gas volumes, respectively, between periods.

Total net revenues increases were also driven by higher average realized sales prices of natural gas for the year ended December 31, 2025 compared to the same 2024 period. This increase was the result of higher regional and national average index gas prices between periods.

These increases were partially offset by lower average realized sale prices for oil and NGLs, which decreased 14% and 12%, respectively, for the year ended December 31, 2025 compared to the same 2024 period. The 14% decrease in the average realized oil price was mainly the result of lower NYMEX crude prices between periods. The 12% decrease in the average realized NGL price between periods was primarily attributable to lower Mont Belvieu spot prices for plant products for the year ended December 31, 2025 compared to the same 2024 period.

Operating Expenses. The following table sets forth selected operating expense data for the periods indicated:

	Year Ended December 31,		Increase/(Decrease)	
	2025	2024	Change	%
Operating costs (in thousands):				
Lease operating expenses	$ 753,119	$ 685,172	$ 67,947	10 %
Severance and ad valorem taxes	390,255	377,731	12,524	3 %
Gathering, processing, and transportation expense	200,103	183,602	16,501	9 %
Operating cost metrics:				
Lease operating expenses (per Boe)	$ 5.26	$ 5.45	$ (0.19)	(3)%
Severance and ad valorem taxes (% of revenue)	7.7 %	7.6 %	0.1 %	1 %
Gathering, processing, and transportation expense (per Boe)	1.40	1.46	(0.06)	(4)%

Lease Operating Expenses. Lease operating expenses ("LOE") per Boe for the year ended December 31, 2025 was $5.26, which represents a 3% decrease compared to the same 2024 period. This decrease in our LOE per Boe rate was primarily driven by lower water disposal rates and wellhead chemicals that resulted from operational efficiencies. While LOE per Boe decreased period over period, total LOE for the year ended December 31, 2025 increased by $67.9 million compared to the year ended December 31, 2024 and was the direct result of our higher well count between periods primarily due to additional wells placed on production or acquired since December 31, 2024.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the year ended December 31, 2025 increased $12.5 million compared to the year ended December 31, 2024. Severance taxes are based on the market value of our production at the wellhead, while ad valorem taxes are generally based on the assessed taxable value of our proved developed oil and gas properties and vary across the different counties in which we operate. The increase in severance and ad valorem tax expense for the year ended 2025 compared to the same 2024 period is due to an increase in severance taxes and is primarily related to higher NGL and natural gas revenues between periods.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation costs ("GP&T") on a per Boe basis decreased from $1.46 for the year ended December 31, 2024 to $1.40 per Boe for the year ended December 31, 2025. This decrease in rate was mainly attributable to lower GP&T rates based on the location of new wells placed on production since the fourth quarter of 2024. While our GP&T per Boe was lower period versus period, total GP&T for the year ended December 31, 2025 increased $16.5 million compared to the year ended December 31, 2024. This increase in expense was mainly attributable to higher NGL and natural gas volumes sold between periods, which in turn resulted in a higher amount of plant processing fees and gathering costs being incurred.

Depreciation, Depletion and Amortization. The following table summarizes our depreciation, depletion and amortization ("DD&A") for the periods indicated:

	Year Ended December 31,	
(in thousands, except per Boe data)	**2025**	**2024**
Depreciation, depletion and amortization	$ 2,032,507	$ 1,776,673
Depreciation, depletion and amortization per Boe	$ 14.18	$ 14.13

For the year ended December 31, 2025, DD&A expense amounted to $2.0 billion, an increase of $255.8 million from 2024. The primary factor contributing to higher DD&A expense in 2025 was the increase in our overall production volumes between periods, which increased DD&A expense by $248.4 million period over period, while marginally higher DD&A rates between periods increased DD&A expense by $7.4 million.

DD&A per Boe was $14.18 for the year ended December 31, 2025 compared to $14.13 for the same period in 2024. Our DD&A rate can fluctuate as a result of finding and development costs incurred, acquisitions, impairments, as well as changes in proved developed and proved undeveloped reserves.

General and Administrative Expenses. The following table summarizes our general and administrative ("G&A") expenses for the periods indicated:

(in thousands, except per Boe data)	**Year Ended December 31, 2025**	**2024**
Cash general and administrative expenses	$ 119,513	$ 116,387
Stock-based compensation expense	66,958	58,243
General and administrative expenses	$ 186,471	$ 174,630
Cash general and administrative expenses per Boe	$ 0.83	$ 0.93

G&A expenses for the year ended December 31, 2025 were $186.5 million compared to $174.6 million for the year ended December 31, 2024. Stock-based compensation increased $8.7 million primarily related to additional grants of performance stock units and restricted stock since the fourth quarter of 2024. This was partially offset by less expenses associated with accelerated vestings of equity awards that occurred during the year ended of December 31, 2024 that did not reoccur during the same 2025 period. Cash G&A was $3.1 million higher between periods mainly related to increased employee expenses and consulting and professional services related to our increased headcount and overall corporate growth.

While cash G&A increased between periods, on a per Boe basis our cash G&A rate decreased 11% from $0.93 per Boe during the year ended December 31, 2024 to $0.83 per Boe during the year ended December 31, 2025. This per Boe rate decrease was the result of focus on controlling costs and growing production.

Other Income and Expense.

Interest Expense. The following table summarizes interest expense for the periods indicated:

(in thousands)	**Year Ended December 31, 2025**	**2024**
Credit Facility	$ 9,536	$ 16,062
5.375% Senior Notes due 2026	11,153	15,556
7.75% Senior Notes due 2026	—	14,016
6.875% Senior Notes due 2027	—	6,397
8.00% Senior Notes due 2027	44,000	44,000
3.25% Convertible Senior Notes due 2028	1,382	5,524
5.875% Senior Notes due 2029	41,124	41,124
9.875% Senior Notes due 2031	33,198	49,376
7.00% Senior Notes due 2032	70,000	70,000
6.25% Senior Notes due 2033	62,500	25,347
Amortization of debt issuance costs, debt discount and debt premium	8,023	6,563
Other interest expense	2,146	2,206
Total	$ 283,062	$ 296,171

Interest expense was $13.1 million lower for the year ended December 31, 2025 compared to the year ended December 31, 2024 mainly due to (i) $45.1 million less interest incurred between periods due to various redemptions and repurchases of our senior notes during the 2024 and 2025 periods (refer to *Note 5—Long-Term Debt* under Part II, Item 8 of this Annual Report for additional information regarding these transactions); and (ii) less interest expense incurred on our credit facility due to lower weighted average borrowings outstanding during the 2025 period. These decreases were partially offset by $37.2 million in additional interest incurred on our 6.25% Senior Notes due 2033 that were issued in July 2024.

Loss on extinguishment of debt. The loss on extinguishment of debt incurred during the year ended December 31, 2025 of $270.1 million was primarily related to the Redemption of our Convertible Senior Notes. This loss was determined based on the difference in the value of our Class A Common Stock issued and cash paid for the Redemption and the carrying amount of the Convertible Senior Notes less professional fees incurred in connection with the Redemption. The 2025 loss was greater than prior debt redemption losses as the Convertible Notes were redeemed mainly by issuing Class A Common Stock, which has risen significantly in value since the Convertible Senior Notes were issued in 2021. Refer to *Note 5—Long-Term Debt* under Part II, Item 8 of this Annual Report for additional information regarding the redemption.

During the year ended December 31, 2024, we recognized $8.6 million of loss on extinguishment of debt related to the redemptions of our 7.75% senior notes due 2026 and 6.875% senior notes due 2027.

Net Gain (Loss) on Derivative Instruments. Net gains and losses are a function of (i) changes in derivative fair values associated with fluctuations in the forward price curves for the commodities underlying each of our hedge contracts outstanding and (ii) monthly cash settlements on any closed out hedge positions during the period.

The following table presents gains and losses on our derivative instruments for the periods indicated:

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Realized cash settlement gains (losses)	$ 277,245	$ 77,203
Non-cash mark-to-market derivative gain (loss)	168,479	17,783
Total	$ 445,724	$ 94,986

Income Tax Expense: The following table summarizes our pre-tax income and income tax expense for the periods indicated:

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Income before income taxes	$ 1,383,115	$ 1,550,851
Income tax expense	(284,179)	(300,342)

For the year ended December 31, 2025 we generated pre-tax net income of $1.4 billion and recorded income tax expense of $284.2 million. Our provision for income tax expense for the year ended December 31, 2025 was less than the amounts that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax book income primarily due to (i) the portion of pre-tax net income that is attributable to our noncontrolling interest partners that is not taxable to the Company; and (ii) general business tax credits generated during the year. These decreases were partially offset by an increase in our unrecognized tax benefit recognized during the year ended December 31, 2025.

For the year ended December 31, 2024, we generated pre-tax net income of $1.6 billion and recorded income tax expense of $300.3 million. The primary factor decreasing our 2024 tax expense below the statutory U.S. federal income tax rate was the portion of pre-tax income that was attributable to our noncontrolling interest partners and not taxable to the Company.

For the Year Ended December 31, 2024 Compared to the Year Ended December 31, 2023

Refer to *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in the 2024 Annual Report on Form 10-K filed with the SEC for a discussion of the results of operations for the year ended December 31, 2024 compared to the year ended December 31, 2023.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations, borrowings under our revolving credit facility, proceeds from offerings of debt or equity securities, or proceeds from the sale of oil and gas properties. Our future cash flows are subject to a number of variables, including oil and natural gas prices, which have been and will likely continue to be volatile. Lower commodity prices can negatively impact our cash flows and our ability to access debt or equity markets, and sustained low oil and natural gas prices could have a material and adverse effect on our liquidity position. To date, our primary uses of capital have been for drilling and development capital expenditures and the acquisition of oil and natural gas properties.

We continually evaluate our capital needs and compare them to our capital resources. Our total capital expenditures incurred for drilling and development activity during the year ended December 31, 2025 were $1.97 billion. We expect our total drilling, completion and facilities capital expenditures budget for 2026 to be between $1.75 billion to $1.95 billion. We funded our capital expenditures for 2025 entirely from cash flows from operations, and we expect to fund our 2026 capital expenditures budget entirely from cash flows from operations given our anticipated level of oil and gas production, current commodity prices and our commodity hedge positions in place.

We are the operator of a high percentage of our acreage and can control the amount and timing of our capital expenditures. Accordingly, we can choose to defer or accelerate a portion of our planned capital expenditures depending on a variety of factors, including but not limited to: (i) prevailing and anticipated prices for oil and natural gas; (ii) oil and gas storage or transportation constraints; (iii) the success of our drilling activities; (iv) the availability of necessary equipment, infrastructure and capital; (v) the receipt and timing of required regulatory permits and approvals; (vi) seasonal conditions; (vii) property or land acquisition costs; and (viii) the level of participation by other working interest owners.

We plan to return capital to shareholders primarily through our base dividend, in addition to opportunistic share repurchases. During the year ended December 31, 2025, we declared and paid quarterly base dividends totaling $0.60 per share of Class A Common Stock and distributions totaling $0.60 per share of Class C Common Stock (each of which has an underlying Common Unit of OpCo). The cash dividends and distributions paid to common unitholders totaled $502.9 million for the year ended December 31, 2025. Additionally, we repurchased 4.4 million shares of Class A Common Stock for $46.8 million and 2.0 million shares of Class C Common Stock for $26.9 million under our Repurchase Program during the year ended December 31, 2025.

Our Repurchase Program can be used to reduce our shares of common stock outstanding. Such repurchases would be made at terms and prices determined by us based upon prevailing market conditions, applicable legal requirements, available liquidity, compliance with our debt agreements and other factors.

In addition, we may, from time to time, seek to retire or purchase our outstanding senior notes through cash purchases and/or exchanges for debt in open-market purchases, privately negotiated transactions or otherwise. During the year ended December 31, 2025, we (i) redeemed an aggregate principal amount of $175 million of our 2031 Senior Notes at a price equal to 109.875% of the aggregate principal amount; (ii) repurchased and redeemed an aggregate principal amount of $289.4 million of our 2026 Senior Notes; and (iii) redeemed the aggregate principal amount of $170 million of our Convertible Senior Notes for 30.6 million shares of our Class A Common Stock at a conversion rate of 179.9208 shares per $1,000 principal amount of Convertible Senior Notes as well as a cash payment of $0.1 million.

Although we cannot provide any assurance that cash flows from operations or other sources of needed capital will be available to us at acceptable terms, or at all, and noting that our ability to access the public or private debt or equity capital markets at economic terms in the future will be affected by general economic conditions, the domestic and global oil and financial markets, our operational and financial performance, the value and performance of our debt or equity securities, prevailing commodity prices and other macroeconomic factors outside of our control, we believe that based on our current expectations and projections, we will have sufficient capital available to fund our capital expenditure requirements through the 12-month period following the filing of this Annual Report and the long-term.

Analysis of Cash Flow Changes

The following table summarizes our cash flows for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Net cash provided by operating activities	$ 3,607,541	$ 3,411,968	$ 2,213,499
Net cash used in investing activities	(2,873,454)	(3,104,195)	(1,578,379)
Net cash (used in) provided by financing activities	(1,059,740)	97,706	(631,188)

Cash Flows from 2025 Compared to 2024. For the year ended December 31, 2025, we generated $3.6 billion of cash from operating activities, an increase of $195.6 million from 2024. Cash provided by operating activities increased primarily due to (i) higher production volumes, realized derivative gains and realized prices for gas, (ii) lower merger and integration and interest expense, and (iii) the timing of payments to our suppliers for the year ended December 31, 2025 as compared to the same 2024 period. These increasing factors were partially offset by lower realized prices for oil and NGLs, higher costs including lease operating expenses, GP&T expense, severance and ad valorem taxes and cash G&A as well as the timing of our receivable collections for the year ended December 31, 2025 as compared to the same 2024 period. Refer to *Results of Operations* for more information on the impact of volumes and prices on revenues and on fluctuations in our operating expenses between periods.

For the year ended December 31, 2025, cash flows from operating activities, cash on hand and proceeds of $176.7 million primarily from the sale of oil and natural gas gathering systems that were acquired during a prior year acquisition were used to (i) fund $1.97 billion of drilling and development cash expenditures; (ii) fund acquisitions of oil and gas properties of approximately $1.1 billion; (iii) pay $502.9 million in dividends and cash distributions to shareholders and holders of our Common Units; (iv) redeem $464.5 million of our senior notes; and (v) repurchase $73.7 million of our Class A and C Common Stock.

Cash Flows from 2024 Compared to 2023. For the year ended December 31, 2024, we generated $3.4 billion of cash from operating activities, an increase of $1.2 billion from 2023. Cash provided by operating activities increased primarily due to higher production volumes and lower merger and integration expense for the year ended December 31, 2024 as compared to the same 2023 period. These increasing factors were partially offset by lower realized prices for oil and natural gas, higher costs including lease operating expenses, severance and ad valorem taxes, interest expense, GP&T expense, and cash G&A as well as the timing of our receivable collections for the year ended December 31, 2024 as compared to the same 2023 period.

For the year ended December 31, 2024, cash flows from operating activities, proceeds from the issuance of our 6.25% Senior Notes due 2033 and proceeds from an underwritten public offering of 26.5 million Class A Common Stock were used to: (i) fund $2.1 billion of drilling and development cash capital expenditures; (ii) fund acquisitions of oil and gas properties of approximately $1.0 billion; (iii) redeem $656.4 million of our senior notes; (iv) pay $560.9 million in dividends and cash distributions to our shareholders and holders of our Common Units; and (v) repurchase $61.0 million of our Class C Common Stock.

Credit Agreement

OpCo, our consolidated subsidiary, has a secured revolving Credit Agreement with a syndicate of banks maturing in February 2028 that, as of December 31, 2025, had a borrowing base of $4.0 billion and elected commitments of $2.5 billion. As of December 31, 2025, we had no borrowings outstanding and $2.5 billion in available borrowing capacity. The elected commitments and borrowing base were reaffirmed during the spring and fall 2025 borrowing base redeterminations.

The Credit Agreement contains restrictive covenants that limit our ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make restricted payments; (v) repurchase or redeem junior debt; (vi) enter into commodity hedges exceeding a specified percentage of our expected production; (vii) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (viii) incur liens; (ix) sell assets; and (x) engage in transactions with affiliates.

The Credit Agreement also requires OpCo to maintain compliance with the following financial ratios:

(i) a current ratio, which is the ratio of OpCo's consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and

(ii) a leverage ratio, which is the ratio of total funded debt to consolidated EBITDAX (with such terms defined within the Credit Agreement) for the most recent quarter annualized, of not greater than 3.5 to 1.0.

The Credit Agreement includes fall away covenants, lower interest rates and reduced collateral requirements that OpCo may elect if OpCo is assigned an Investment Grade Rating (as defined within the Credit Agreement). OpCo was in compliance with the covenants and financial ratios under the Credit Agreement described above through the filing of this Annual Report. For further information on the Credit Agreement, refer to *Note 5—Long-Term Debt* under Item 8 of this Annual Report.

Senior Notes

OpCo has $3.5 billion in debt outstanding as of December 31, 2025, consisting of senior unsecured notes with maturity dates ranging from 2027 to 2033. For further information on our Senior Unsecured Notes, refer to *Note 5—Long-Term Debt* under Part II, Item 8 of this Annual Report.

Obligations and Commitments

We routinely enter into or extend operating and transportation agreements, office and equipment leases, drilling rig contracts, among others, in the ordinary course of business. The following table summarizes our obligations and commitments as of December 31, 2025, to make future payments under long-term contracts for the time periods specified below.

(in thousands)	2026	2027	2028	2029	2030	Thereafter	Total
Operating leases[1]	$ 82,790	$ 40,462	$ 12,194	$ 2,483	$ 2,202	$ 1,885	$ 142,016
Finance leases[2]	791	754	718	685	653	12,712	16,313
Purchase obligations[3]	50,507	15,251	13,233	724	—	—	79,715
Firm transportation[4]	28,885	78,282	107,169	118,033	118,032	769,179	1,219,580
Development obligation[5]	20,000	—	—	—	—	—	20,000
Asset retirement obligations[6]	22,503	2,841	2,827	1,447	467	159,265	189,350
Long term debt obligations[7]	—	550,000	—	700,000	—	2,325,000	3,575,000
Cash interest expense on long-term debt obligations[8]	259,094	227,927	206,969	185,270	164,594	220,683	1,264,537
Total	$ 464,570	$ 915,517	$ 343,110	$1,008,642	$ 285,948	$3,488,724	$ 6,506,511

(1) Operating leases consist of our office rental agreements, drilling rig contracts and other wellhead equipment. Please refer to *Note 15—Leases* under Part II, Item 8 of this Annual Report for details on our operating lease commitments.

(2) Finance leases consist of our ground lease related to the office building we purchased in Midland, Texas. The lease term is ninety-nine years and as a result, the commitments above have been shown at their current present value. Please refer to *Note 15—Leases* under Part II, Item 8 of this Annual Report for details on our finance lease commitments.

(3) Consists of energy purchase agreements to buy a minimum amount of electricity at a fixed price or pay for underutilization as well as a take-or-pay agreement to purchase a minimum volume of frac sand at a fixed price. The obligations reported above represent our remaining minimum financial commitments pursuant to the terms of these contracts as of December 31, 2025, however actual expenditures may exceed the minimum commitments presented above. Please refer to *Note 13—Commitments and Contingencies* under Part II, Item 8 of this Annual Report for details on these agreements.

(4) Consists of firm transportation commitment agreements that guarantee volumetric capacity on pipelines for gas transportation. Please refer to *Note 13—Commitments and Contingencies* under Part II, Item 8 of this Annual Report for details on these agreements.

(5) Consists of obligations that are tied to our future drilling, completion and water connection activity in Reeves County, Texas that will require repayment if certain performance obligations through September 2026 are not met.

(6) Asset retirement obligations reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and gas wells and the related land restoration in accordance with applicable laws and regulations.

(7) Long-term debt consists of the principal amounts of our senior notes due as of December 31, 2025.

(8) Cash interest expense on our senior notes is estimated assuming no principal repayment until the maturity of the instruments. Cash interest expense on the Credit Agreement includes unused commitment fees and assumes no additional principal borrowings, repayments or changes to commitments under the agreement through the instrument due date.

Recently Issued Accounting Standards

Refer to *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, in Part II, Item 8. Financial Statements and Supplementary Data in this annual report for a discussion of recently issued accounting standards and their anticipated effect on our business.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these statements requires us to make certain assumptions, judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as, the disclosure of contingent assets, contingent liabilities and commitments as of the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, commodity prices, production performance, drilling results, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies can be found in *Note 1—Basis of Presentation and Summary of Significant Accounting Policies* under Item 8 of this Annual Report.

We have outlined certain of our accounting policies below which require the application of significant judgment by our management.

Oil and Natural Gas Reserve Quantities

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil, NGL and natural gas reserves. Reserve quantities and the related estimates of future net cash flows are used as inputs to our calculation of depletion, evaluation of proved properties for impairment, assessment of the expected realizability of our deferred income tax assets, and the standardized measure of discounted future net cash flows computations.

The process of estimating quantities of proved reserves is inherently imprecise and relies on the following: i) interpretations and judgment of available geological, geophysical, engineering and production data; ii) certain economic assumptions, some of which are mandated by the SEC, such as commodity prices; and iii) assumptions and estimates of underlying inputs such as operating expenses, capital expenditures, plug and abandonment costs and taxes. All of these assumptions may differ substantially from actual results, which could result in a significant change in our estimated quantities of proved reserves and their future net cash flows. We continually make revisions to reserve estimates throughout the year as additional information becomes available, and we make changes to depletion rates in the same reporting period that changes to reserve estimates are made.

Business Combinations

From time to time, we may complete acquisitions that are accounted for as business combinations that require us to recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the acquisition date. Determining fair value requires management's judgment and involves the use of significant estimates and assumptions with respect to projections of future production volumes, forecasted development costs, pricing and cash flows, discount rates, expectations regarding customer contracts and relationships, reserve risk adjustment factors and other management estimates. The judgments made in the determination of the estimated fair value assigned to the assets acquired, liabilities assumed and any noncontrolling interest, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition. See *Note 2—Business Combinations* in Item 8 of this Annual Report on Form 10-K.

Impairment of Oil and Natural Gas Properties

We assess our proved properties for impairment when events or changes in circumstances indicate that the carrying value of such proved property assets may not be recoverable. For purposes of an impairment evaluation, our proved oil and natural gas properties must be grouped at the lowest level for which independent cash flows can be identified. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to its estimated fair value. Fair value for the purpose of measuring impairment write-downs are calculated using the present value of expected future cash flows that are estimated to be generated from the asset group. Fair value estimates are based on projected financial information which we believe to be reasonably likely to occur, as of the date that the impairment write-down is being measured. However, such future cash flow estimates are based on numerous assumptions that can materially affect our estimates, and such assumptions are subject to change with variations in commodity prices, production performance, drilling results, operating and development costs, underlying oil and gas reserve quantities, and other internal or external factors.

Unproved properties consist of the costs we incur to acquire undeveloped leasehold acreage and unproved reserves. Unproved properties are periodically assessed for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. Changes in our assessment or these factors could result in additional impairment charges of our undeveloped leases.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The term "market risk" as it applies to our business refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates, and we are exposed to market risk as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our primary market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Pricing for oil, NGLs and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue for the foreseeable future. Based on our production for the year ended December 31, 2025, our oil and gas sales for the year ended December 31, 2025 would have moved up or down $425.1 million for each 10% change in oil prices per Bbl, $65.9 million for each 10% change in NGL prices per Bbl and $13.2 million for each 10% change in natural gas prices per Mcf.

Due to this volatility, we have historically used, and we may elect to continue to selectively use, commodity derivative instruments (such as collars, swaps, puts and basis swaps) to mitigate price risk associated with a portion of our anticipated production. Our derivative instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flows that can emanate from fluctuations in oil and natural gas prices, and thereby provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil and natural gas prices, but alternatively they partially limit our potential gains from future increases in prices. Our Credit Agreement limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production from proved properties.

The table below summarizes the terms of the derivative contracts we had in place as of December 31, 2025 and additional contracts entered into through February 20, 2026. Refer to *Note 8—Derivative Instruments* under Part II, Item 8 of this Annual Report for open derivative positions as of December 31, 2025.

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Crude Price ($/Bbl)
Crude oil swaps - NYMEX WTI	January 2026 - March 2026	5,355,000	59,500	$64.62
	April 2026 - June 2026	6,324,500	69,500	63.70
	July 2026 - September 2026	4,554,000	49,500	65.79
	October 2026 - December 2026	4,554,000	49,500	65.16

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)
Crude oil basis differential swaps(1)	January 2026 - March 2026	4,485,000	49,833	$0.94
	April 2026 - June 2026	6,324,500	69,500	0.91
	July 2026 - September 2026	3,634,000	39,500	1.02
	October 2026 - December 2026	3,634,000	39,500	1.02

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)
Crude oil roll differential swaps - NYMEX WTI	January 2026 - March 2026	3,405,000	37,833	$0.26
	April 2026 - June 2026	5,232,500	57,500	0.31
	July 2026 - September 2026	2,530,000	27,500	0.33
	October 2026 - December 2026	2,530,000	27,500	0.33

(1) These crude oil basis swap transactions are settled utilizing the ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - NYMEX Henry Hub	January 2026 - March 2026	12,330,000	137,000	$4.23
	April 2026 - June 2026	12,467,000	137,000	3.57
	July 2026 - September 2026	12,604,000	137,000	3.83
	October 2026 - December 2026	12,604,000	137,000	4.16
	January 2027 - March 2027	12,600,000	140,000	4.24
	April 2027 - June 2027	12,740,000	140,000	3.32
	July 2027 - September 2027	12,880,000	140,000	3.58
	October 2027 - December 2027	12,880,000	140,000	3.94

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - Waha	January 2026 - March 2026	8,550,000	95,000	$2.66
	April 2026 - June 2026	8,645,000	95,000	0.43
	July 2026 - September 2026	8,740,000	95,000	1.80
	October 2026 - December 2026	15,145,000	164,620	2.73
	January 2027 - March 2027	7,650,000	85,000	3.57

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - HSC	January 2026 - March 2026	9,000,000	100,000	4.40
	April 2026 - June 2026	9,100,000	100,000	3.63
	July 2026 - September 2026	9,200,000	100,000	3.95
	October 2026 - December 2026	9,200,000	100,000	4.24

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Differential ($/MMBtu)
Natural gas basis differential swaps(1)	January 2026 - March 2026	12,330,000	137,000	$(1.34)
	April 2026 - June 2026	12,467,000	137,000	(2.31)
	July 2026 - September 2026	12,604,000	137,000	(1.42)
	October 2026 - December 2026	12,604,000	137,000	(1.21)
	January 2027 - March 2027	14,490,000	161,000	(0.47)
	April 2027 - June 2027	14,651,000	161,000	(1.11)
	July 2027 - September 2027	14,812,000	161,000	(0.65)
	October 2027 - December 2027	14,812,000	161,000	(0.91)

(1) These natural gas basis swap contracts are settled utilizing the Inside FERC's West Texas Waha price and the NYMEX Henry Hub price of natural gas.

Changes in the fair value of derivative contracts from December 31, 2024 to December 31, 2025, are presented below:

(in thousands)	Commodity derivative asset (liability)
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2024	$ 111,356
Commodity hedge contract settlement payments, net of any receipts	(277,245)
Cash and non-cash mark-to-market gains (losses) on commodity hedge contracts[1]	445,724
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2025	$ 279,835

(1) At inception, new derivative contracts entered into by us have no intrinsic value.

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2025 would cause a $82.9 million increase or decrease in this fair value position, and a hypothetical upward or downward shift of 10% per MMBtu in the NYMEX forward curve for natural gas as of December 31, 2025 would cause a $36.1 million increase or decrease in this same fair value position.

Interest Rate Risk

Our ability to borrow and the rates offered by lenders can be adversely affected by deteriorations in the credit markets and/or downgrades in our credit rating. OpCo's Credit Agreement interest rate is based on a SOFR spread, which exposes us to interest rate risk to the extent we have borrowings outstanding under this credit facility. As of December 31, 2025, we had no borrowings outstanding under the Credit Agreement. We do not currently have or intend to enter into any derivative hedge contracts to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

The long-term debt balance of $3.5 billion consists of our senior notes, which have fixed interest rates; therefore, this balance is not affected by interest rate movements. For additional information regarding our debt instruments, see *Note 5—Long-Term Debt* in Item 8 of this Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PERMIAN RESOURCES CORPORATION
INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Permian Resources Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Permian Resources Corporation and subsidiaries (the Company) as of December 31, 2025 and 2024, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated 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 years in the three-year period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2026 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Estimation of oil and gas reserves on depletion expense related to proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, capitalized proved property acquisition and development costs are depleted on a units-of-production method, which is based on the estimated oil and gas reserves remaining. For the year ended December 31, 2025, the Company recorded depreciation, depletion and amortization expense of $2 billion. The estimation of economically recoverable proved oil and gas reserves requires the expertise of professional petroleum reserve engineers who take into consideration forecasted production, development cost assumptions and forecasted oil and gas prices. The Company annually engages independent reserve engineers to estimate the proved oil and gas reserves and the Company's internal reserve engineers update the estimates of proved oil and gas reserves on a quarterly basis.

We identified the estimation of oil and gas reserves on depletion expense related to proved oil and gas properties as a critical audit matter. There was a high degree of subjectivity in evaluating the estimate of proved oil and gas reserves, which is a significant input into the calculation of depletion. Subjective auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production, development costs, and oil and natural gas pricing.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's process to estimate depletion expense related to proved oil and gas properties. This included controls related to the assumptions used in the proved oil and gas reserves estimate, and to calculate depletion expense. We evaluated (1) the professional qualifications of the Company's internal reserve engineers as well as the independent reserve engineers and independent engineering firm, (2) the knowledge, skills, and ability of the Company's internal and independent reserve engineers, and (3) the relationship of the independent reserve engineers and independent engineering firm to the Company. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We assessed the data used in the average of the first-day-of-the-month pricing assumptions used in the internal reserve engineers' and the independent reserve engineers' estimates of the proved reserves by comparing them to publicly available oil and natural gas benchmark pricing data, and existing contractual arrangements. We evaluated assumptions used in the internal reserve engineers' and independent reserve engineers' estimates regarding future development costs by comparing them to historical costs. Additionally, we compared the forecasted production volumes to historical production, and we compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast. We read the report of the Company's independent reserve engineers in order to understand the methods and assumptions used by the independent reserve engineers in connection with our evaluation of the Company's reserve estimates. We compared reserve quantity information to the corresponding information used for depletion expense and recalculated the depletion expense for compliance with regulatory standards.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Dallas, Texas
February 26, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Permian Resources Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Permian Resources Corporation and subsidiaries' (the Company) 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. In our opinion, the Company maintained, in all material respects, effective 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements), and our report dated February 26, 2026 expressed an unqualified opinion on those consolidated 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 Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Dallas, Texas

February 26, 2026

PERMIAN RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

	December 31, 2025	December 31, 2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 153,690	$ 479,343
Accounts receivable, net	840,653	530,452
Derivative instruments	279,725	85,509
Prepaid and other current assets	38,075	26,290
Total current assets	1,312,143	1,121,594
Property and equipment		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,933,409	1,990,441
Proved properties	21,484,903	18,595,780
Accumulated depreciation, depletion and amortization	(7,168,925)	(5,163,124)
Total oil and natural gas properties, net	16,249,387	15,423,097
Other property and equipment, net	57,051	50,381
Total property and equipment, net	16,306,438	15,473,478
Noncurrent assets		
Operating lease right-of-use assets	132,764	119,703
Other noncurrent assets	160,840	183,125
TOTAL ASSETS	$ 17,912,185	$ 16,897,900
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 1,453,610	$ 1,198,418
Operating lease liabilities	79,496	57,216
Other current liabilities	144,726	71,703
Total current liabilities	1,677,832	1,327,337
Noncurrent liabilities		
Long-term debt, net	3,545,598	4,184,233
Asset retirement obligations	166,847	148,443
Deferred income taxes	893,463	602,379
Operating lease liabilities	55,102	64,288
Other noncurrent liabilities	39,460	52,701
Total liabilities	6,378,302	6,379,381
Commitments and contingencies (Note 13)		
Shareholders’ equity		
Common stock, $0.0001 par value, 1,500,000,000 shares authorized:		
Class A: 757,854,120 shares issued and 751,746,410 shares outstanding at December 31, 2025 and 707,388,380 shares issued and 703,774,082 shares outstanding at December 31, 2024	76	71
Class C: 84,378,125 shares issued and outstanding at December 31, 2025 and 99,599,640 shares issued and outstanding at December 31, 2024	8	10
Additional paid-in capital	8,710,698	8,056,552
Retained earnings (accumulated deficit)	1,567,500	1,081,895
Total shareholders’ equity	10,278,282	9,138,528
Noncontrolling interest	1,255,601	1,379,991
Total equity	11,533,883	10,518,519
TOTAL LIABILITIES AND EQUITY	$ 17,912,185	$ 16,897,900

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

PERMIAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2025	2024	2023
Operating revenues			
Oil and gas sales	$ 5,065,211	$ 5,000,734	$ 3,120,893
Operating expenses			
Lease operating expenses	753,119	685,172	373,772
Severance and ad valorem taxes	390,255	377,731	240,762
Gathering, processing and transportation expenses	200,103	183,602	89,282
Depreciation, depletion and amortization	2,032,507	1,776,673	1,007,576
General and administrative expenses	186,471	174,630	161,855
Merger and integration expense	—	18,064	125,331
Impairment and abandonment expense	7,985	9,912	6,681
Exploration and other expenses	32,042	30,791	19,337
Total operating expenses	3,602,482	3,256,575	2,024,596
Net gain (loss) on sale of long-lived assets	—	375	211
Income from operations	1,462,729	1,744,534	1,096,508
Other income (expense)			
Interest expense	(283,062)	(296,171)	(177,209)
Loss on extinguishment of debt	(270,120)	(8,585)	—
Net gain (loss) on derivative instruments	445,724	94,986	114,016
Other income (expense)	27,844	16,087	2,333
Total other income (expense)	(79,614)	(193,683)	(60,860)
Income before income taxes	1,383,115	1,550,851	1,035,648
Income tax expense	(284,179)	(300,342)	(155,945)
Net income	1,098,936	1,250,509	879,703
Less: Net income attributable to noncontrolling interest	(163,762)	(265,808)	(403,397)
Net income attributable to Class A Common Stock	$ 935,174	$ 984,701	$ 476,306
Income per share of Class A Common Stock:			
Basic	$ 1.31	$ 1.54	$ 1.36
Diluted	$ 1.28	$ 1.45	$ 1.24

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

PERMIAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income	$ 1,098,936	$ 1,250,509	$ 879,703
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,032,507	1,776,673	1,007,576
Stock-based compensation expense	70,371	60,399	78,418
Impairment and abandonment expense	7,985	9,912	6,681
Deferred tax expense	285,400	299,019	152,383
Net (gain) loss on sale of long-lived assets	—	(375)	(211)
Non-cash portion of derivative (gain) loss	(168,479)	(17,783)	(14,606)
Amortization of debt issuance costs, discount and premium	8,023	6,563	11,326
Loss on extinguishment of debt	270,120	8,585	—
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(321,456)	(51,396)	36,336
(Increase) decrease in prepaid and other assets	(23,288)	(8,491)	(27,267)
Increase (decrease) in accounts payable and other liabilities	347,422	78,353	83,160
Net cash provided by operating activities	3,607,541	3,411,968	2,213,499
Cash flows from investing activities:			
Acquisition of oil and natural gas properties, net	(1,070,547)	(1,047,128)	(234,288)
Drilling and development capital expenditures	(1,965,926)	(2,060,667)	(1,524,899)
Cash (paid) received for businesses acquired in mergers, net of cash received	—	—	39,832
Purchases of other property and equipment	(13,682)	(12,845)	(34,483)
Contingent considerations received related to divestiture	—	—	60,000
Proceeds from sales of oil and natural gas properties	176,701	16,445	115,459
Net cash used in investing activities	(2,873,454)	(3,104,195)	(1,578,379)
Cash flows from financing activities:			
Proceeds from equity offering, net	—	402,211	—
Proceeds from borrowings under revolving credit facility	—	1,965,000	1,950,000
Repayment of borrowings under revolving credit facility	—	(1,965,000)	(2,335,000)
Repayment of credit facility acquired in mergers	—	—	(830,000)
Proceeds from issuance of senior notes	—	1,000,000	997,500
Debt issuance and redemption costs	(18,767)	(26,498)	(15,169)
Redemption of senior notes	(464,548)	(656,351)	—
Proceeds from exercise of stock options	219	257	534
Share repurchases	(73,700)	(61,048)	(162,420)
Dividends paid	(447,714)	(466,915)	(141,947)
Distributions paid to noncontrolling interest owners	(55,230)	(93,950)	(94,686)
Net cash (used in) provided by financing activities	(1,059,740)	97,706	(631,188)
Net increase (decrease) in cash, cash equivalents and restricted cash	(325,653)	405,479	3,932
Cash, cash equivalents and restricted cash, beginning of period	479,343	73,864	69,932
Cash, cash equivalents and restricted cash, end of period	$ 153,690	$ 479,343	$ 73,864

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

PERMIAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
(in thousands)

	Year Ended December 31,		
	2025	2024	2023
Supplemental cash flow information			
Cash paid for interest	$ 288,731	$ 267,081	$ 140,069
Cash paid (refunded) for income taxes	(812)	6,818	3,603
Supplemental non-cash activity			
Equity issued and long-term debt assumed to acquire oil and gas properties	$ —	$ 100,371	$ 4,873,949
Equity issued to redeem Convertible Senior Notes	430,021	—	—
Accrued capital expenditures included in accounts payable and accrued expenses	248,307	291,574	325,069
Deferred tax liability assumed in asset acquisition and merger	—	—	344,223
Asset retirement obligations incurred, including revisions to estimates	23,670	34,683	83,446
Dividends payable	10,390	8,534	3,504

Reconciliation of cash, cash equivalents and restricted cash presented in the consolidated statements of cash flows:

	Year Ended December 31,		
	2025	2024	2023
Cash and cash equivalents	$ 153,690	$ 479,343	$ 73,290
Restricted cash(1)	—	—	574
Total cash, cash equivalents and restricted cash	$ 153,690	$ 479,343	$ 73,864

(1) Included in *Prepaid and other current assets* as of December 31, 2023.

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

PERMIAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Stock								
	Class A		Class C		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total Shareholder's Equity	Non-controlling Interest	Total Equity
	Shares	Amount	Shares	Amount					
Balance at December 31, 2022	298,640	$ 30	269,300	$ 27	$ 2,698,465	$ 237,226	$ 2,935,748	$ 2,720,548	$ 5,656,296
Restricted stock issued	1,204	—	—	—	—	—	—	—	—
Issuance of Class A Common Stock	161,166	16	—	—	2,288,014	—	2,288,030	—	2,288,030
Issuance of Class C Common Stock, net of tax	—	—	49,534	5	(164,494)	—	(164,489)	864,919	700,430
Restricted stock forfeited	(814)	—	—	—	—	—	—	—	—
Share repurchases - Class A	(6,761)	(1)	—	—	(75,959)	—	(75,960)	—	(75,960)
Share repurchases - Class C	—	—	(7,202)	(1)	1	—	—	(86,460)	(86,460)
Issuance of Common Stock under Employee Stock Purchase Plan	56	—	—	—	241	—	241	—	241
Performance stock vested and issued	10,372	1	—	—	(1)	—	—	—	—
Stock-based compensation	—	—	—	—	78,418	—	78,418	—	78,418
Stock option exercises	79	—	—	—	534	—	534	—	534
Dividends	—	—	—	—	—	(144,393)	(144,393)	—	(144,393)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(94,683)	(94,683)
Conversion of common shares from Class C to Class A, net of tax	80,669	8	(80,669)	(8)	934,713	—	934,713	(905,102)	29,611
Equity impact from transactions effecting Common Units, net of tax of $2.0 million	—	—	—	—	6,949	—	6,949	(8,968)	(2,019)
Net income	—	—	—	—	—	476,306	476,306	403,397	879,703
Balance at December 31, 2023	544,611	$ 54	230,963	$ 23	$ 5,766,881	$ 569,139	$ 6,336,097	$ 2,893,651	$ 9,229,748
Restricted stock issued	2,476	—	—	—	—	—	—	—	—
Restricted stock forfeited	(735)	—	—	—	—	—	—	—	—
Share repurchases - Class C	—	—	(3,800)	—	—	—	—	(61,048)	(61,048)
Issuance of Class A Common Stock	32,742	4	—	—	502,579	—	502,583	—	502,583
Performance stock vested and issued	709	—	—	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	60,399	—	60,399	—	60,399
Stock option exercises	22	—	—	—	257	—	257	—	257
Dividends	—	—	—	—	—	(471,945)	(471,945)	—	(471,945)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(93,950)	(93,950)
Conversion of common shares from Class C to Class A, net of tax	127,563	13	(127,563)	(13)	1,744,570	—	1,744,570	(1,647,914)	96,656
Equity impact from transactions effecting Common Units, net of tax of $5.3 million	—	—	—	—	(18,134)	—	(18,134)	23,444	5,310
Net income	—	—	—	—	—	984,701	984,701	265,808	1,250,509
Balance at December 31, 2024	707,388	$ 71	99,600	$ 10	$ 8,056,552	$ 1,081,895	$ 9,138,528	$ 1,379,991	$10,518,519

PERMIAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (continued)
(in thousands)

	Common Stock								
	Class A		Class C		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total Shareholder's Equity	Non-controlling Interest	Total Equity
	Shares	Amount	Shares	Amount					
Restricted stock issued	4,719	—	—	—	—	—	—	—	—
Restricted stock forfeited	(578)	—	—	—	—	—	—	—	—
Share repurchases - Class A	(4,370)	—	—	—	(46,779)	—	(46,779)	—	(46,779)
Share repurchases - Class C	—	—	(2,000)	(1)	—	—	(1)	(26,920)	(26,921)
Performance stock vested and issued	6,870	1	—	—	(1)	—	—	—	—
Stock-based compensation	—	—	—	—	70,371	—	70,371	—	70,371
Stock option exercises	34	—	—	—	219	—	219	—	219
Dividends	—	—	—	—	—	(449,569)	(449,569)	—	(449,569)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(55,230)	(55,230)
Conversion of common shares from Class C to Class A, net of tax	13,222	1	(13,222)	(1)	192,793	—	192,793	(196,317)	(3,524)
Convertible senior notes redemption	30,569	3	—	—	430,018	—	430,021	—	430,021
Equity impact from transactions effecting Common Units, net of tax of $2.2 million	—	—	—	—	7,525	—	7,525	(9,685)	(2,160)
Net income	—	—	—	—	—	935,174	935,174	163,762	1,098,936
Balance at December 31, 2025	757,854	$ 76	84,378	$ 8	$ 8,710,698	$ 1,567,500	$ 10,278,282	$ 1,255,601	$11,533,883

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

Note 1—Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

Permian Resources Corporation is an independent oil and natural gas company focused on the acquisition, optimization and development of crude oil and associated liquids-rich natural gas reserves. The Company's assets and operations are located in the Permian Basin, with a concentration in the core of the Delaware Basin. Its properties consist of large, contiguous acreage blocks located in West Texas and New Mexico. Unless otherwise specified or the context otherwise requires, all references in these notes to "Permian Resources" or the "Company" are to Permian Resources Corporation and its consolidated subsidiaries including, Permian Resources Operating, LLC ("OpCo").

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Company, its subsidiary OpCo and OpCo's wholly-owned subsidiaries and have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") and the rules and regulations of the United States Securities and Exchange Commission ("SEC"). All intercompany balances and transactions have been eliminated in consolidation. Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Noncontrolling interests represent third-party ownership in OpCo and is presented as a component of equity. See *Note 10—Shareholders' Equity and Noncontrolling Interest* for a discussion of noncontrolling interest.

Use of Estimates

The preparation of the Company's consolidated financial statements requires the Company's management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events, and accordingly, actual results could differ from amounts previously established. Additionally, the prices received for oil, NGL and natural gas production can heavily influence the Company's assumptions, judgments and estimates, and continued volatility of oil and gas prices could have a significant impact on the Company's estimates.

The more significant areas requiring the use of assumptions, judgments and estimates include: (i) oil and natural gas reserves; (ii) cash flow estimates used in impairment tests for long-lived assets; (iii) impairment expense of unproved properties; (iv) depreciation, depletion and amortization; (v) asset retirement obligations; (vi) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (vii) accrued revenues and related receivables; (viii) accrued liabilities; (ix) derivative valuations; (x) deferred income taxes; and (xi) determining the fair values of certain stock-based compensation awards.

Cash and Cash Equivalents and Restricted Cash

The Company considers all highly liquid instruments with an original maturity of 3 months or less at the time of issuance to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short-term maturity of these investments. From time to time, the Company is required to maintain cash in separate accounts, the use of which is restricted by the terms of contracted arrangements. The Company had no restricted cash as of December 31, 2025 and December 31, 2024.

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Accordingly, the Company's oil and natural gas receivables are generally collected, and the Company has minimal bad debts.

Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized, and the Company therefore establishes an allowance for doubtful accounts equal to the portions of its accounts receivable for which collectability is not reasonably assured. The Company had no allowance for doubtful accounts as of December 31, 2025 and December 31, 2024.

Credit Risk and Other Concentrations

Permian Resources is exposed to credit risk in the event of nonpayment by counterparties. The Company normally sells production to a relatively small number of customers, as is customary in its business. The table below summarizes the purchasers that accounted for 10% or more of the Company's total net revenues in at least one of the periods presented:

	Year Ended December 31,		
	2025	2024	2023
Enterprise Crude Oil, LLC	34 %	19 %	30 %
Shell Trading (US) Company[(1)]		31 %	20 %
BP America[(1)]		11 %	20 %

(1) During the year ended December 31, 2025, these customers accounted for less than 10% of our total net revenues.

During these periods, no other purchaser accounted for 10% or more of the Company's net revenues. The loss of any of the Company's major purchasers could materially and adversely affect its revenues in the short-term. However, based on the demand for oil and natural gas and the availability of other purchasers, the Company believes that the loss of any major purchaser would not have a material adverse effect on its financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company also exposes itself to credit risk. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; and (ii) only entering into hedging arrangements with counterparties that are also participants in OpCo's credit agreement, all of which have investment-grade credit ratings.

Oil and Natural Gas Properties

The Company's oil and natural gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete development wells are capitalized to proved properties. Exploration costs, including personnel and other internal costs, geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Costs of drilling exploratory wells, on the other hand, are initially capitalized but are charged to expense if the well is determined to be unsuccessful. Costs to operate, repair and maintain wells and field equipment are expensed as incurred.

Proved Properties. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, NGLs and natural gas are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, extension wells and service wells, are capitalized. Capitalized proved property acquisition and development costs are depleted using a units-of production method based on the remaining life of proved and proved developed reserves, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized. Gains or losses from the disposal of complete units of depreciable property are recognized to the consolidated statements of operations.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that there could be a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital and operating expenditures and discount rates, which are based on a weighted average cost of capital. There were no impairments of proved oil and natural gas properties for the years ended December 31, 2025, 2024 and 2023.

Unproved Properties. Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves, and they are both capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or a right in a property such as a lease, in addition to broker fees, recording fees and other similar costs related to acquiring properties.

Leasehold costs are classified as unproved until proved reserves are discovered on or otherwise attributed to the property, at which time the related unproved property costs are transferred to proved oil and natural gas properties.

The Company evaluates unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. Any portion of unproved properties deemed unlikely to be developed for proved reserves or otherwise determined to be recoverable is charged as impairment expense upon such determination. Impairments of unproved properties are included in *Impairment and abandonment expense* in the consolidated statements of operations.

Other Property and Equipment

Other property and equipment includes office furniture and equipment, buildings, vehicles, computer hardware and software and is recorded at cost. These assets are depreciated using the straight-line method over their estimated useful lives which range from three to twenty years. Equipment upgrades and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts and a gain or loss is recorded in the consolidated statements of operations as needed.

Debt Issuance Costs, Discounts and Premiums

Debt issuance costs related to the Company's revolving credit facility are included in the line item *Other Noncurrent Assets* in the consolidated balance sheets. These costs are amortized to interest expense on a straight-line basis over the borrowing term. Issuance costs incurred in connection with the Company's senior notes offerings and any related issuance discount or premium are deferred and charged to interest expense over the term of the agreement; however, these amounts are reflected as a reduction of or addition to the related obligation in the line item *Long-term debt* on the consolidated balance sheets.

Derivative Financial Instruments

In order to mitigate its exposure to oil and natural gas price volatility, the Company may periodically use derivative instruments, such as swaps, costless collars, basis swaps, and other similar agreements. The Company's derivatives have not been designated as hedges for accounting purposes.

The Company records derivative instruments in its consolidated balance sheets as either an asset or liability measured at fair value. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The commodity derivative instruments are accounted for using mark-to-market accounting where all gains and losses are recognized in earnings during the period in which they are incurred.

Asset Retirement Obligations

The Company recognizes a liability for the estimated future costs associated with abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired. The fair value of the liability recognized is based on the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The Company depletes the amount added to proved oil and natural gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

Prepayments

The Company, from time to time, may require joint interest owners to pay for their proportionate share of future development costs prior to commencement of a capital projects. Such amounts are recorded as liabilities and are recognized as reductions of future joint interest billings as the related costs are incurred. As of December 31, 2025 and 2024, prepayments totaled $97.0 million and $33.2 million, respectively, and are included within *Other current liabilities* in the consolidated balance sheets.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, NGLs and natural gas. Revenue is recognized when a performance obligation is satisfied by transferring control of the produced oil, NGLs or natural gas to the customer. For all commodity products, the Company records revenue in the month production is delivered to the purchaser based on estimates of the amount of production delivered to the purchaser and the price the Company will receive. Payments are generally received between 30 and 60 days after the date of production. Variances between estimated sales and actual amounts received are typically insignificant and are recorded in the month payment is received. Refer to *Note 14—Revenues* for additional information.

Income Taxes

The Company is subject to U.S. federal, state and local income taxes with respect to its allocable share of any taxable income of OpCo, as well as any stand-alone income generated by the Company. OpCo is treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, OpCo is not subject to U.S. federal and certain state and local income taxes. Any taxable income generated by OpCo is passed through to and included in the taxable income of its members, including the Company, on a pro rata basis.

Deferred income tax assets and liabilities are recognized based on temporary differences resulting from: (i) net operating loss carryforwards for income tax purposes, (ii) tax credit carryfowards, and (iii) differences between the amounts recorded to the consolidated financial statements and the tax basis of assets and liabilities, as measured using enacted statutory tax rates in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates or tax laws is recognized in income during the period such changes are enacted. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized.

Stock-Based Compensation

The Company's stock-based compensation consists of grants of restricted stock, stock options, and performance stock units to employees and directors. The Company determines compensation expense related to all equity-based awards based on their estimated fair value, and such expense is recognized on a straight-line basis over the applicable service period of the award. For cash settled awards classified as liabilities, compensation expense is estimated based on the fair value of the awards as of the balance sheet date, and such expense is recognized ratably over the period in which the award is expected to be paid. See *Note 7—Stock-Based Compensation* for additional information regarding the Company's stock-based compensation.

Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing net income attributable to the Company's Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Dilutive EPS is calculated by dividing adjusted net income attributable to Class A Common Stock by the weighted average shares of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. See *Note 11—Earnings Per Share* for additional information regarding the Company's computation of EPS.

Segment Reporting

The nature of the Company's operations and geographical location of such are concentrated to exploration and production of oil and natural gas within the Permian Basin. The Company's chief operating decision maker ("CODM") is each of its Co-Chief Executive Officers who manage and review the Company's operations on a consolidated basis. Accordingly, the Company operates in one reportable segment.

The CODM uses consolidated net income to measure profit or loss, assess performance and make key operating decisions. Additionally, the CODM utilizes cash flows to facilitate investment decisions, including determining future levels of developmental capital expenditures, assessing potential acquisitions and divestitures, assessing appropriate returns of capital to shareholders and other strategic sources and uses of capital. The CODM does not generally evaluate performance using asset information. Consolidated net income and all significant expenses are reported within the Company's consolidated statements of operations while cash flows are presented on the Company's consolidated statement of cash flows.

Recently Issued or Adopted Accounting Standards

In November 2024, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2024-03, *Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures*, which requires public business entities to disclose specific expense categories in the notes to the financial statements. This ASU is effective for annual periods beginning after December 15, 2026 and interim periods beginning after December 15, 2027. The Company is currently assessing the impact of this ASU on the Company's financial statements.

In December 2023, the FASB issued ASU No. 2023-09, *Improvements to Income Tax Disclosures* ("ASU 2023-09"), which was intended to enhance income tax disclosures by requiring disclosure of items such as the disaggregation of the income tax rate reconciliation as well as information regarding income taxes paid. The Company adopted the provisions of ASU 2023-09 prospectively and have included the required disclosures in this Annual Report in *Note 12—Income Taxes*.

Note 2—Business Combinations

Bolt-On Acquisition

On September 17, 2024, the Company completed its acquisition of oil and gas properties with certain affiliates of Occidental Petroleum Corporation (the "Bolt-On Acquisition"). The Bolt-On Acquisition included approximately 29,500 net leasehold acres and approximately 9,900 net royalty acres that are predominately located directly offsetting the Company's existing assets in Reeves County, Texas, as well as Eddy County, New Mexico. The Bolt-On Acquisition was completed to drive long-term accretion across the Company's key financial and operating metrics, enhance shareholder returns and add core inventory locations to the Company's existing position in the Permian Basin.

Purchase Price Allocation

The Bolt-On Acquisition has been accounted for as a business combination using the acquisition method of accounting in accordance with Accounting Standards Codification ("ASC") Topic 805, *Business Combinations* ("ASC 805"). Under the acquisition method of accounting, the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition closing date, which requires judgment and certain estimates and assumptions to be made. Oil and natural gas properties were valued using an income-based approach, which incorporates a discounted cash flow method. The pro forma impact of this business combination to revenues and net income is not disclosed as it was deemed not to have a material impact on the Company's results of operations.

The purchase price allocation was finalized during the year ended December 31, 2025. The following table represents the final consideration and purchase price allocation of the identifiable assets acquired and the liabilities assumed based on their respective fair values as of the closing date of the Bolt-On Acquisition.

(in thousands, except share and per share data)	Bolt-On Acquisition Consideration
Total cash consideration given	$ 775,826
Fair value of assets acquired:	**Purchase Price Allocation**
Accounts receivable, net	$ 1,134
Oil and natural gas properties, net	806,543
Total assets acquired	$ 807,677
Fair value of liabilities assumed:	
Accounts payable and accrued expenses	$ 16,697
Asset retirement obligations	15,154
Total liabilities assumed	$ 31,851
Net assets acquired	$ 775,826

Earthstone Merger

On November 1, 2023 the Company completed its merger (the "Earthstone Merger") with Earthstone Energy, Inc. ("Earthstone"). In connection with the Earthstone Merger, the Board of Directors of both companies unanimously determined (i) each share of Earthstone Class A common stock was converted into the right to receive 1.446 shares (the "Exchange Ratio") of Permian Resources Class A Common Stock, (ii) each share of Earthstone Class B common stock was converted into the right to receive 1.446 shares of Permian Resources Class C Common Stock and (iii) each common unit of Earthstone Energy Holdings, LLC ("Earthstone OpCo"), a subsidiary of Earthstone, representing limited liability company membership interests in Earthstone OpCo (the "Earthstone OpCo Unit holders") was converted into the right to receive a number of common units representing limited liability company interests in OpCo ("Common Units") equal to the Exchange Ratio. As a result, the Company issued 161.2 million shares of its Class A Common Stock and 49.5 million shares of its Class C Common Stock to Earthstone stockholders under the terms of the merger agreement governing the Earthstone Merger.

Earthstone was an independent oil and gas company engaged in the operation and development of oil and natural gas properties in the Permian Basin in both Texas and New Mexico. Earthstone's assets consisted of approximately 167,000 net leasehold acres in the Midland Basin and 56,000 net leasehold acres in the Delaware Basin, and Earthstone's Delaware Basin acreage was offset to Permian Resources' existing acreage in Lea and Eddy Counties. The Earthstone Merger was completed to drive long-term accretion across the Company's key financial and operating metrics, enhance shareholder returns, improve capital efficiency, and add significant core inventory locations to the Company's existing position in the Permian Basin.

Post-Acquisition Operating Results

The results of Earthstone's operations have been included in the Company's consolidated financial statements since November 1, 2023, the effective date of the Earthstone Merger. For the year ended December 31, 2023, approximately $337.3 million of operating revenues and $211.8 million of direct operating expenses attributable to Earthstone's business have been included in the consolidated statements of operations.

In connection with the Earthstone Merger, the Company incurred certain merger-related integration and transaction costs that are expensed as incurred. For the years ended December 31, 2024 and 2023, the Company recognized transaction costs of $18.1 million and $106.9 million, respectively, which are included in *Merger and integration expense* in the consolidated statements of operations. These costs primarily relate to bankers' advisory, legal, consultancy and accounting fees, as well as severance and related benefits for employees that were terminated in connection with the Earthstone Merger.

Supplemental Unaudited Pro Forma Financial Information

The following supplemental unaudited pro forma financial information ("pro forma information") for the year ended December 31, 2023 has been prepared from the respective historical consolidated financial statements of the Company and has been adjusted to reflect the Earthstone Merger as if it had been completed on January 1, 2022.

The pro forma information is not necessarily indicative of the results that might have occurred had the merger occurred in the past and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma information.

	Year Ended December 31, 2023
Total Revenue	$ 4,769,673
Net Income	896,900
Earnings per share:	
Basic	$ 1.86
Diluted	1.55

Note 3—Acquisitions and Divestitures

Asset Acquisitions

On June 16, 2025, the Company completed its acquisition of approximately 13,000 net leasehold acres with Apache Corporation for an unadjusted purchase price of $608 million. The acreage acquired is predominately located directly offsetting the Company's existing asset position in the core of its New Mexico operating area. The acquisition was recorded as an asset acquisition in accordance with ASC 805. Total consideration paid was $572.3 million after settlement statement adjustments, of which $500.6 million was allocated to proved properties and $80.8 million to unproved properties on a relative fair value basis with the remaining $9.1 million related to liabilities assumed.

During the year ended December 31, 2025, the Company completed multiple acquisitions of oil and natural gas properties for a cumulative adjusted purchase price of approximately $471.1 million. These transactions were recorded as asset acquisitions in accordance with ASC 805.

During the year ended December 31, 2024, the Company completed multiple acquisitions of oil and natural gas properties for a cumulative adjusted purchase price of approximately $392.3 million. These transactions were recorded as asset acquisitions in accordance with ASC 805.

Note 4—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	December 31, 2025	December 31, 2024
Oil and gas sales receivable, net	$ 435,017	$ 326,393
Joint interest billings, net	314,835	188,474
Derivative settlements receivable	41,866	8,585
Other receivables	48,935	7,000
Accounts receivable, net	$ 840,653	$ 530,452

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	December 31, 2025	December 31, 2024
Accounts payable	$ 70,528	$ 45,965
Accrued capital expenditures	205,050	267,213
Revenues payable	854,633	589,454
Employee compensation and benefits payable	28,462	28,550
Interest payable	105,367	121,204
Accrued expenses and other payables	189,570	146,032
Accounts payable and accrued expenses	$ 1,453,610	$ 1,198,418

Note 5—Long-Term Debt

The following table provides information about the Company's long-term debt as of the dates indicated:

(in thousands)	December 31, 2025	December 31, 2024
Credit Facility due 2028	$ —	$ —
Senior Notes		
5.375% Senior Notes due 2026	—	289,448
8.00% Senior Notes due 2027	550,000	550,000
3.25% Convertible Senior Notes due 2028	—	170,000
5.875% Senior Notes due 2029	700,000	700,000
9.875% Senior Notes due 2031	325,000	500,000
7.00% Senior Notes due 2032	1,000,000	1,000,000
6.25% Senior Notes due 2033	1,000,000	1,000,000
Unamortized debt issuance costs on Senior Notes	(24,405)	(31,545)
Unamortized debt (discount)/premium	(4,997)	6,330
Senior Notes, net	3,545,598	4,184,233
Total long-term debt, net	$ 3,545,598	$ 4,184,233

Credit Agreement

OpCo, the Company's consolidated subsidiary, has a credit agreement with a syndicate of banks that provides for a secured revolving credit facility, maturing in February 2028 (the "Credit Agreement") that had a borrowing base of $4.0 billion, elected commitments of $2.5 billion and no borrowings outstanding as of December 31, 2025.

In connection with the fall borrowing base redetermination on October 24, 2025, the Company entered into the tenth amendment to its Credit Agreement (the "Tenth Amendment"). The Tenth Amendment, among other things, (i) reaffirmed the borrowing base at $4.0 billion, (ii) reaffirmed the aggregate elected revolving commitments at $2.5 billion, and (iii) adjusted the applicable margin by (a) adding a new borrowing base utilization pricing grid applicable on any day during a borrowing base period on which the Company has an index debt rating of BBB- or better from Fitch Ratings, Inc. and (b) subject to certain conditions, reducing the interest rates applicable on any day during an investment grade period. Additionally, on December 22, 2025, OpCo entered into the eleventh amendment to its Credit Agreement that, among other things, made certain technical amendments to the Credit Agreement to permit the corporate reorganization described in *Note 16—Subsequent Events.*

The amount available to be borrowed under the Credit Agreement is equal to the lesser of: (i) the borrowing base, which is set at $4.0 billion; (ii) aggregate elected revolving commitments, which is set at $2.5 billion as of December 31, 2025; or (iii) $6.0 billion. The borrowing base is redetermined semi-annually in the spring and fall by the lenders in their sole discretion. It also allows for the Company to request two optional borrowing base redeterminations in between the scheduled redeterminations; one at the Borrower's request and an additional one in connection with any Material Acquisition (as defined in the Credit Agreement). The borrowing base depends on, among other things, the quantities of OpCo's proved oil and natural gas reserves, estimated cash flows from those reserves, and the Company's commodity hedge positions. Upon a redetermination of the borrowing base, if actual borrowings outstanding exceed the revised borrowing capacity, OpCo could be required to immediately repay a portion of its debt outstanding in an amount equal to the excess. Borrowings under the Credit Agreement are guaranteed by certain of

OpCo's subsidiaries.

Borrowings under the Credit Agreement may be base rate loans or SOFR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for SOFR loans. SOFR loans bear interest at SOFR plus an applicable margin ranging from 162.5 to 262.5 basis points, depending on the percentage of elected commitments utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; or (iii) the adjusted Term SOFR rate for a one-month interest period plus 100 basis points, plus an applicable margin, ranging from 62.5 to 162.5 basis points, depending on the percentage of the borrowing base utilized. OpCo also pays a commitment fee of 37.5 to 50 basis points on unused elected commitment amounts under its facility.

The Credit Agreement contains restrictive covenants that limit our ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make restricted payments; (v) repurchase or redeem junior debt; (vi) enter into commodity hedges exceeding a specified percentage of our expected production; (vii) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (viii) incur liens; (ix) sell assets; and (x) engage in transactions with affiliates.

The Credit Agreement also requires OpCo to maintain compliance with the following financial ratios:

(i) a current ratio, which is the ratio of OpCo's consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and

(ii) a leverage ratio, which is the ratio of total funded debt to consolidated EBITDAX (with such terms defined within the Credit Agreement) for the most recent quarter annualized, of not greater than 3.5 to 1.0.

The Credit Agreement includes fall away covenants, lower interest rates and reduced collateral requirements that OpCo may elect if OpCo is assigned an Investment Grade Rating (as defined within the Credit Agreement).

OpCo was in compliance with the covenants and the applicable financial ratios described above as of December 31, 2025.

Convertible Senior Notes

In March 2021, OpCo issued $170 million in aggregate principal amount of 3.25% senior unsecured convertible notes due 2028 (the "Convertible Senior Notes") resulting in aggregate net proceeds to OpCo of $163.6 million, after deducting debt issuance costs of $6.4 million. Interest was payable on the Convertible Senior Notes semi-annually in arrears on each April 1 and October 1 with a maturity date of April 1, 2028.

The Convertible Senior Notes could be settled by paying or delivering, as applicable, cash, shares of Class A Common Stock, or a combination of cash and shares of Class A Common Stock, at OpCo's election. On or after April 7, 2025, the Convertible Senior Notes could be redeemed at a redemption price equal to 100% of the principal amount, plus accrued and unpaid interest to the date of redemption, if the last reported sale price per share of Class A Common Stock exceeded 130% of the conversion price (i) for any 20 trading days during the 30 consecutive trading days ending on the day immediately before the date OpCo sends the related redemption notice; and (ii) also on the trading day immediately before the date OpCo sends such notice.

On August 28, 2025, the Company issued a redemption notice (the "Redemption Notice") to holders of the Convertible Senior Notes ("Holders") calling for the redemption of all outstanding Convertible Senior Notes (the "Redemption"). The Redemption Notice allowed Holders the right to convert each $1,000 principal amount of the Convertible Senior Notes for 179.9208 shares of Class A Common Stock (the "Conversion Rate") or a cash redemption price of $1,014.53. Certain Holders exercised their right to convert $169.9 million aggregate principal amount of the Convertible Senior Notes for 30.6 million shares of Class A Common Stock based on the Conversion Rate. The Class A Common Stock issued in the Redemption was valued at $430.0 million based on the trading price of the Company's Class A Common Stock on the date of each conversion and was recorded as an increase to additional paid-in capital within the consolidated balance sheets. The remaining $0.1 million principal amount of Convertible Senior Notes was redeemed for cash.

The Redemption was accounted for as an extinguishment of debt in accordance with ASC 470-50, *Modifications and Extinguishments,* which resulted in a loss on extinguishment of debt of $263.9 million being recognized in the consolidated statement of operations during the year ended December 31, 2025. This loss on extinguishment of debt consisted of the difference in the value of the Class A Common Stock issued and cash paid for the Redemption and the carrying amount of the Convertible Senior Notes less professional fees incurred in connection with the Redemption.

Capped Called Transactions

In connection with the issuance of the Convertible Senior Notes in March 2021, OpCo entered into privately negotiated capped call spread transactions with option counterparties (the "Capped Call Transactions"). The Capped Call Transactions cover the aggregate number of shares of Class A Common Stock that initially underlie the Convertible Senior Notes and have a strike price of $6.28 per share of Class A Common Stock and a capped price of $8.4525 per share of Class A Common Stock, each of which are subject to certain customary adjustments upon the occurrence of certain corporate events, as defined in the capped call agreements. Following the Redemption, the Company elected to keep the Capped Call Transactions outstanding and the instruments are scheduled to expire on April 1, 2028.

Senior Unsecured Notes

The 8.00% senior notes due 2027 (the "2027 Senior Notes"), 5.875% senior notes due 2029 (the "2029 Senior Notes"), 9.875% senior notes due 2031 (the "2031 Senior Notes"), 7.00% senior notes due 2032 (the "2032 Senior Notes") and 6.25% senior notes due 2033 (the "2033 Senior Notes") (collectively, the "Senior Unsecured Notes") are unsecured senior obligations. The Senior Unsecured Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Company and each of OpCo's current subsidiaries that guarantee borrowings under OpCo's Credit Agreement.

The table below summarizes the interest rates, interest payment dates, principal amounts outstanding and the maturity dates related to OpCo's outstanding senior unsecured note obligations as of December 31, 2025.

(in thousands)	Interest Rate	Interest Payment Dates	Principal Amount	Maturity Date
Senior Notes due 2027	8.00%	April 15, October 15	$ 550,000	April 15, 2027
Senior Notes due 2029	5.875%	January 1, July 1	700,000	July 1, 2029
Senior Notes due 2031	9.875%	January 15, July 15	325,000	July 15, 2031
Senior Notes due 2032	7.00%	January 15, July 15	1,000,000	January 15, 2032
Senior Notes due 2033	6.25%	February 1, August 1	1,000,000	February 1, 2033

On or after the dates in the following schedule (the "Optional Redemption Date"), OpCo has the option to redeem the Senior Unsecured Notes, in whole or in part, at the applicable redemption prices set forth in the indenture documents, plus accrued and unpaid interest on the date of redemption. At any time prior to Optional Redemption Dates, OpCo may, on any one or more occasions, redeem all or a part of the Senior Unsecured Notes at a redemption price equal to 100% of the principal amount of the Senior Unsecured Notes redeemed, plus a "make-whole" premium, and any accrued and unpaid interest as of the date of redemption.

	Optional Redemption Date	Redemption Price(1)
Senior Notes due 2027	April 15, 2024	102.000%
Senior Notes due 2029	July 1, 2024	101.469%
Senior Notes due 2031	July 15, 2026	104.940%
Senior Notes due 2032(2)	January 15, 2027	103.500%
Senior Notes due 2033(2)	August 1, 2027	103.125%

(1) The redemption price represents the redeemable price of the Senior Unsecured Notes on the Optional Redemption Date or as of December 31, 2025, for the Senior Unsecured Notes whose Optional Redemption Date has already passed. The redemption prices decreases annually to 100% of the principal amount redeemed plus accrued and unpaid interest.

(2) At any time prior to the Optional Redemption Date, OpCo may redeem up to 40% of the aggregate principal amount with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 107.000% (for the 2032 Senior Notes) or 106.25% (for the 2033 Senior Notes) of the principal amount plus accrued and unpaid interest up to the redemption date; provided that at least 60% of the aggregate principal amount remains outstanding immediately after such redemption, and the redemption occurs within 180 days of the closing date of such equity offering.

If OpCo experiences certain defined changes of control accompanied by a ratings decline, each holder of the Senior Unsecured Notes may require OpCo to repurchase all or a portion of its Senior Unsecured Notes for cash at a price equal to 101% of the aggregate principal amount of such Senior Unsecured Notes, plus any accrued but unpaid interest to the date of repurchase.

The indentures governing the Senior Unsecured Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit OpCo's ability and the ability of OpCo's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. OpCo was in compliance with these covenants as of December 31, 2025 and through the filing of this Annual Report.

Upon an Event of Default (as defined in the indentures governing the Senior Unsecured Notes), the trustee or the holders of at least 25% (or in the case of the 2029 Senior Notes, 30%) of the aggregate principal amount of then outstanding Senior Unsecured Notes may declare the Senior Unsecured Notes immediately due and payable. In addition, a default resulting from certain events of bankruptcy or insolvency with respect to OpCo, any restricted subsidiary of OpCo that is a significant subsidiary, or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary, will automatically cause all outstanding Senior Unsecured Notes to become due and payable.

Partial Senior Note Repurchase and Redemptions

During June 2025, the Company repurchased $2.7 million of the 5.375% senior notes due 2026 (the "2026 Senior Notes") at a price equal to 99.7% of the principal amount paid plus accrued and unpaid interest up to, but excluding, the repurchase date. Subsequently, on September 20, 2025, the Company redeemed all remaining outstanding 2026 Senior Notes at a price equal to 100% of the aggregate principal amount outstanding of $286.7 million plus accrued and unpaid interest up to, but excluding, the redemption date.

During January 2025, the Company redeemed $175 million of its 2031 Senior Notes at a redemption price equal to 109.875% of the principal amount redeemed plus accrued and unpaid interest up to, but excluding, the redemption date. The Company paid total consideration of $192.3 million, excluding interest, resulting in a loss on extinguishment of debt of $5.8 million after writing off the carrying value of the 2031 Senior Notes of $186.5 million, which included the associated pro rata unamortized debt premium. Following the redemption, the remaining aggregate principal amount of the 2031 Senior Notes outstanding was $325 million.

In August 2024, the Company redeemed all of its $299.6 million outstanding 2026 7.75% Senior Notes through a cash tender offer and the Company irrevocably elected to redeem the remaining amount of the 2026 7.75% Senior Notes outstanding pursuant to the terms of the indenture governing the 2026 7.75% Senior Notes. The Company paid total consideration for the tender offer and redemption, excluding accrued interest, of $305.1 million.

On April 5, 2024, the Company redeemed all of OpCo's outstanding 2027 6.875% Senior Notes at a redemption price equal to 100% of the aggregate principal amount outstanding of $356.4 million plus accrued and unpaid interest up to, but excluding, the redemption date.

Issuance of Senior Notes

On August 5, 2024, OpCo issued at par $1.0 billion of 6.25% senior notes due 2033 (the "2033 Senior Notes") in a 144A private placement that resulted in net proceeds to the Company of $986.4 million, after deducting $13.6 million debt issuance costs.

Note 6—Asset Retirement Obligations

The following table summarizes changes in the Company's asset retirement obligations ("ARO") associated with its working interests in oil and gas properties for the periods presented:

(in thousands)	December 31, 2025	December 31, 2024
Asset retirement obligations, beginning of period	$ 160,089	$ 121,417
Liabilities acquired	13,992	24,204
Liabilities incurred	9,691	10,964
Liabilities divested and settled	(5,974)	(5,435)
Accretion expense	11,565	9,424
Revision to estimated cash flows	(13)	(485)
Asset retirement obligations, end of period	189,350	160,089
Less current portion[1]	(22,503)	(11,646)
Asset retirement obligations - long-term, end of period	$ 166,847	$ 148,443

[1] The current portion of ARO is included within *Other current liabilities* in the consolidated balance sheets.

ARO reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. Inherent in the fair value calculation of ARO are numerous estimates and assumptions, including plug and abandonment settlement amounts, inflation factors, credit adjusted discount rates and the timing of settlement. To the extent future revisions to these assumptions impact the value of the existing ARO liabilities, a corresponding offsetting adjustment is made to the oil and gas property balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability with an offsetting charge to accretion expense, which is included within depreciation, depletion and amortization.

Note 7—Stock-Based Compensation

The Company has a Long Term Incentive Plan (the “LTIP”) that has a total of 71,718,560 shares of Class A Common Stock authorized for issuance. The LTIP provides for grants of restricted stock, stock options (including incentive stock options and nonqualified stock options), restricted stock units (including performance stock units), stock appreciation rights and other stock or cash-based awards.

Stock-based compensation expense is recognized within both *General and administrative expenses* and *Exploration and other expenses* in the consolidated statements of operations. The Company accounts for forfeitures of awards granted under the LTIP as they occur.

The following table summarizes stock-based compensation expense recognized for the periods presented:

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Equity Awards			
Restricted stock	$ 30,171	$ 26,216	$ 34,762
Stock option awards	—	—	1
Performance stock units	40,200	34,183	43,655
Total stock-based compensation expense	$ 70,371	$ 60,399	$ 78,418

Equity Awards

The Company has restricted stock, stock options and performance stock units (“PSUs”) outstanding that were granted under the LTIP as discussed below. Each award has service-based and, in the case of the PSUs, market-based vesting requirements, and is expected to be settled in shares of Class A Common Stock upon vesting. As a result, these awards are classified as equity-based awards in accordance with ASC Topic 718, *Compensation-Stock Compensation* (“ASC 718”).

In connection with the merger (the “Colgate Merger”) with Colgate Energy Partners III, LLC (“Colgate”) and Colgate Energy Partners III MidCo, LLC (the “Colgate Unit holder”), the Compensation Committee of the Company’s Board of Directors (the “Compensation Committee”) approved a resolution to extend severance benefits under the Company’s Second Amended and Restated Severance Plan (the “Second A&R Severance Plan”) to employees that experience a Qualifying Termination (as defined in the Second A&R Severance Plan) following the Colgate Merger. As a result, affected employees of the Company received an accelerated vesting of their unvested restricted stock awards and PSUs upon termination, which changed the terms of the vesting conditions and were treated as modifications in accordance with ASC 718. A total of forty-eight employees and two non-employee directors had Qualifying Terminations related to the Colgate Merger, all of which received accelerated vesting of their unvested stock awards or had changes in their service periods resulting in modifications of such impacted stock awards. These modifications resulted in an increase to total stock-based compensation expense of $14.6 million and $40.0 million for the years ended December 31, 2024 and 2023, respectively, as a result of the change in the fair value of the modified awards. The restricted stock shares and performance stock units that were accelerated are included within the vested line items in the below tables. As of September 1, 2024, no additional Qualifying Terminations pursuant to the Second A&R Severance Plan can occur as a result of the Colgate Merger.

Restricted Stock

The following table provides information about restricted stock activity during the year ended December 31, 2025:

	Restricted Stock	Weighted Average Fair Value
Unvested balance as of December 31, 2024	3,614,303	$ 12.64
Granted	4,719,206	14.26
Vested	(1,647,463)	11.16
Forfeited	(578,331)	13.86
Unvested balance as of December 31, 2025	6,107,715	14.17

The Company grants service-based restricted stock to certain officers and employees, which either vests ratably over a three-year service period or cliff vests upon an eighteen month to five-year service period, and to directors, which vest over a one-year service period. Compensation cost for these service-based restricted stock grants is based on the closing market price of the Company's Class A Common Stock on the grant date, and such costs are recognized ratably over the applicable vesting period. The weighted average fair value for restricted stock granted was $14.26, $14.90 and $10.99 per share for the years ended December 31, 2025, 2024 and 2023, respectively. The total fair value of restricted stock that vested for the years ended December 31, 2025, 2024 and 2023 was $18.4 million, $19.7 million and $35.8 million, respectively. Unrecognized compensation cost related to restricted shares that were unvested as of December 31, 2025 was $60.9 million, which the Company expects to recognize over a weighted average period of 2.2 years.

Stock Options

Stock options that have been granted under the LTIP expire ten years from the grant date and vest ratably over their three-year service period. The exercise price for an option granted under the LTIP is the closing market price of the Company's Class A Common Stock on the grant date. Compensation cost for stock options is based on the grant-date fair value of the award, which is then recognized ratably over the vesting period of three years. No stock options were granted during the years ended December 31, 2025, 2024 and 2023.

The following table provides information about stock option awards outstanding during the year ended December 31, 2025:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of December 31, 2024	388,033	$ 16.10		$ 628
Exercised	(35,000)	6.58		$ 257
Expired	(113,500)	19.00		
Outstanding as of December 31, 2025	239,533	16.11	1.8	$ 339
Exercisable as of December 31, 2025	239,533	16.11	1.8	$ 339

The total fair value of stock options that vested and the intrinsic value of the stock options exercised during the years ended December 31, 2025, 2024 and 2023 were minimal. As of December 31, 2025, there was no unrecognized compensation cost related to unvested stock options.

Performance Stock Units

The Company grants PSUs to certain officers and members of management that are subject to market-based vesting criteria as well as a service period of three years. Vesting at the end of the service period depends on the Company's absolute annualized total shareholder return ("TSR") over the performance period, as well as the Company's TSR relative to the TSR of a group of peer companies. These market-based conditions must be met in order for the stock awards to vest, and it is therefore possible that no shares could ultimately vest. However, the Company recognizes compensation expense for the PSUs subject to market conditions regardless of whether it becomes probable that these conditions will be met or not, and compensation expense is not reversed if vesting does not actually occur.

The Company's PSUs currently outstanding can be settled in either Class A Common Stock or cash upon vesting at the Company's discretion. The Company intends to settle all PSUs in Class A Common Stock and has sufficient shares available under the LTIP to settle the units in Class A Common Stock at the potential future vesting dates. Accordingly, the PSUs have been treated as equity-based awards with their fair values determined as of the grant or modification date, as applicable. The fair values of the awards are estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's Class A Common Stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods.

Each of our Co-Chief Executive Officers received performance-based restricted stock unit awards in September 2022 (the "2022 PSUs") which were split into three tranches with performance period end dates at the end of 2025, 2026 and 2027 and with service periods corresponding to those same performance periods. During the third quarter of 2024, the Compensation Committee amended the 2022 PSUs to deem the service requirement portion of the 2022 PSUs met on each of the three tranches as of September 1, 2025, which is consistent with the three-year service requirement for other performance-based restricted stock awards granted by the Company. Following September 1, 2025, each tranche of the 2022 PSUs will continue to be subject to the original performance-based conditions, including no changes to the performance period, and will continue to vest, if at all, based on the satisfaction of the original performance conditions at year-end 2025, 2026 and 2027. In accordance with ASC 718, no incremental stock-based compensation was recognized as a result of these modifications, instead the remaining unrecognized compensation cost was recognized over the modified requisite service period.

The following table summarizes the key assumptions and related information used to determine the fair value of PSUs measured during the periods presented:

	Year Ended December 31,		
	2025	2024	2023
Weighted average fair value per share	$19.53	$24.81	$18.19
Weighted Average Expected implied stock volatility	34.6%	43.9%	55.4%
Weighted Average risk-free interest rate	4.2%	4.3%	4.2%

The following table provides information about PSUs outstanding during the year ended December 31, 2025:

	Awards	Weighted Average Fair Value
Unvested balance as of December 31, 2024	5,343,399	$ 16.54
Granted	2,216,934	19.53
Vested[(1)]	(2,301,088)	16.20
Forfeited	(20,636)	22.34
Unvested balance as of December 31, 2025	5,238,609	17.93

(1) This balance includes vested PSU awards as of December 31, 2025 based on the original number of PSUs granted. Actual PSUs vested is based upon the Company's absolute annualized TSR calculation and the Company's TSR relative to the TSR of a peer group of companies at the time of vesting, which may be greater than or less than the original number granted.

The total fair value of PSUs that vested during the years ended December 31, 2025, 2024 and 2023 were $37.3 million, $14.7 million and $41.1 million, respectively. As of December 31, 2025, there was $35.8 million of unrecognized compensation cost related to PSUs that were unvested, which the Company expects to recognize on a pro-rata basis over a weighted average period of 1.8 years.

Note 8—Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations and may use derivative instruments to manage its exposure to commodity price risk from time to time.

Commodity Derivative Contracts

Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. The Company may periodically use derivative instruments, such as swaps, costless collars, basis swaps, and other similar agreements, to mitigate its exposure to declines in commodity prices and to the corresponding negative impacts such declines can have on its cash flows from operations, returns on capital and other financial results. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not enter into derivative contracts for speculative or trading purposes.

Commodity Swaps. The Company may use commodity derivative instruments known as fixed price swaps to realize a known price for a specific volume of production or basis swaps to hedge the difference between the index price and a local or future index price. All transactions are settled in cash with one party paying the other for the resulting difference in price multiplied by the contract volume.

The following table summarizes the approximate volumes and average contract prices of derivative contracts the Company had in place as of December 31, 2025:

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Crude Price ($/Bbl)
Crude oil swaps - NYMEX WTI	January 2026 - March 2026	4,455,000	49,500	$65.28
	April 2026 - June 2026	4,504,500	49,500	64.71
	July 2026 - September 2026	2,714,000	29,500	68.13
	October 2026 - December 2026	2,714,000	29,500	67.57

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)
Crude oil basis differential swaps[(1)]	January 2026 - March 2026	3,555,000	39,500	$0.98
	April 2026 - June 2026	3,594,500	39,500	0.98
	July 2026 - September 2026	2,714,000	29,500	1.07
	October 2026 - December 2026	2,714,000	29,500	1.07

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)
Crude oil roll differential swaps - NYMEX WTI	January 2026 - March 2026	2,475,000	27,500	$0.20
	April 2026 - June 2026	2,502,500	27,500	0.20
	July 2026 - September 2026	1,610,000	17,500	0.28
	October 2026 - December 2026	1,610,000	17,500	0.28

(1) These crude oil basis swap transactions are settled utilizing the ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - NYMEX Henry Hub	January 2026 - March 2026	12,330,000	137,000	$4.23
	April 2026 - June 2026	12,467,000	137,000	3.57
	July 2026 - September 2026	12,604,000	137,000	3.83
	October 2026 - December 2026	12,604,000	137,000	4.16
	January 2027 - March 2027	12,600,000	140,000	4.24
	April 2027 - June 2027	12,740,000	140,000	3.32
	July 2027 - September 2027	12,880,000	140,000	3.58
	October 2027 - December 2027	12,880,000	140,000	3.94

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - Waha	January 2026 - March 2026	8,550,000	95,000	$2.66
	April 2026 - June 2026	8,645,000	95,000	0.43
	July 2026 - September 2026	8,740,000	95,000	1.80
	October 2026 - December 2026	15,145,000	164,620	2.73
	January 2027 - March 2027	7,650,000	85,000	3.57

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)
Natural gas swaps - HSC	January 2026 - March 2026	9,000,000	100,000	4.40
	April 2026 - June 2026	9,100,000	100,000	3.63
	July 2026 - September 2026	9,200,000	100,000	3.95
	October 2026 - December 2026	9,200,000	100,000	4.24

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Differential ($/MMBtu)
Natural gas basis differential swaps(1)	January 2026 - March 2026	12,330,000	137,000	$(1.34)
	April 2026 - June 2026	12,467,000	137,000	(2.31)
	July 2026 - September 2026	12,604,000	137,000	(1.42)
	October 2026 - December 2026	12,604,000	137,000	(1.21)
	January 2027 - March 2027	14,490,000	161,000	(0.47)
	April 2027 - June 2027	14,651,000	161,000	(1.11)
	July 2027 - September 2027	14,812,000	161,000	(0.65)
	October 2027 - December 2027	14,812,000	161,000	(0.91)

(1) These natural gas basis swap contracts are settled utilizing the Inside FERC's West Texas Waha price and the NYMEX Henry Hub price of natural gas.

Derivative Instrument Reporting. The Company's oil and natural gas derivative instruments have not been designated as hedges for accounting purposes. Therefore, all gains and losses are recognized in the Company's consolidated statements of operations. All derivative instruments are recorded at fair value in the consolidated balance sheets, other than derivative instruments that meet the "normal purchase normal sale" exclusion, and any fair value gains and losses are recognized in current period earnings.

The following table presents the impact of the Company's derivative instruments in its consolidated statements of operations for the periods presented:

	Year Ended December 31,		
(in thousands)	2025	2024	2023
Net gain (loss) on derivative instruments	$ 445,724	$ 94,986	$ 114,016

Offsetting of Derivative Assets and Liabilities. The Company's commodity derivatives are included in the accompanying consolidated balance sheets as derivative assets and liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master netting agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The tables below summarize the fair value amounts and the classification in the consolidated balance sheets of the Company's derivative contracts outstanding at the respective balance dates, as well as the gross recognized derivative assets, liabilities and offset amounts:

	Balance Sheet Classification	Gross Fair Value Asset/ Liability Amounts	Gross Amounts Offset[(1)]	Net Recognized Fair Value Assets/ Liabilities
(in thousands)		December 31, 2025		
Derivative Assets				
Commodity contracts	Derivative instruments	$ 281,752	$ (2,027)	$ 279,725
	Other noncurrent assets	8,733	(7,987)	746
Derivative Liabilities				
Commodity contracts	Other current liabilities	$ 2,027	$ (2,027)	$ —
	Other noncurrent liabilities	8,623	(7,987)	636
		December 31, 2024		
Derivative Assets				
Commodity contracts	Derivative instruments	$ 95,771	$ (10,262)	$ 85,509
	Other noncurrent assets	32,858	(3,971)	28,887
Derivative Liabilities				
Commodity contracts	Other current liabilities	$ 13,302	$ (10,262)	$ 3,040
	Other noncurrent liabilities	3,971	(3,971)	—

(1) The Company has agreements in place with each of its counterparties that allow for the financial right of offset for derivative assets against derivative liabilities at settlement or in the event of a default under the agreements or if contracts are terminated.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are primarily lenders under OpCo's Credit Agreement. The Company enters into new hedge arrangements only with participants under its Credit Agreement, since these institutions are secured equally with the holders of any OpCo bank debt, which eliminates the potential need to post collateral when the Company is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

In addition, the Company is exposed to credit risk associated with its derivative contracts from non-performance by its counterparties. The Company mitigates its exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a lender under OpCo's Credit Agreement as referenced above.

Note 9—Fair Value Measurements

Recurring Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurement and Disclosure,* which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The following table presents, for each applicable level within the fair value hierarchy, the Company's net derivative assets and liabilities, including both current and noncurrent portions, measured at fair value on a recurring basis:

(in thousands)	Level 1	Level 2	Level 3
December 31, 2025			
Total assets	$ —	$ 280,471	$ —
Total liabilities	—	636	—
December 31, 2024			
Total assets	$ —	$ 114,396	$ —
Total liabilities	—	3,040	—

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. There were no transfers between any of the fair value levels during any period presented.

Derivatives

The Company uses Level 2 inputs to measure the fair value of its oil and natural gas commodity derivatives. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations. Refer to *Note 8—Derivative Instruments* for details of the gross and net derivative assets, liabilities and offset amounts as presented in the consolidated balance sheets.

Nonrecurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a nonrecurring basis to its non-financial assets and liabilities, including proved oil and gas properties. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances.

Oil and Gas Property Acquisitions. The fair value measurements of assets acquired and liabilities assumed are measured on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; (vi) a market participant-based weighted average cost of capital rate and (vii) risk adjustment factors applied to proved and unproved reserves. These inputs require significant judgements and estimates by the Company's management at the time of valuation. Refer to *Note 2—Business Combinations* for additional information on the fair value of assets acquired and liabilities assumed.

Impairment of Oil and Natural Gas Properties. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that the fair value of these assets may be below their carrying value. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows from oil and gas properties is less than the carrying amount of the assets. In this circumstance, the Company then recognizes impairment expense for the amount by which the carrying amount of proved properties exceeds their estimated fair value. The Company reviews its oil and natural gas properties on a field-by-field basis.

The Company calculates the estimated fair value of its oil and natural gas properties using an income approach that is based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the expected future net cash flows used for the impairment review and the related fair value measurement of oil and natural gas proved properties include estimates of: (i) oil and gas reserves; (ii) future production decline rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; and (v) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management. The impairment test performed by the Company indicated that no impairment occurred during the years ended December 31, 2025, 2024 and 2023.

*Asset Retirement Obligation*s. The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include the estimated future costs to plug and abandon oil and gas properties and reserve lives. Refer to *Note 6—Asset Retirement Obligations* for additional information on the Company's ARO.

Other Financial Instruments

The carrying amounts of the Company's cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate their fair values because of the short-term maturities and/or liquid nature of these assets and liabilities.

The Company's senior notes and borrowings under its Credit Agreement are accounted for at cost. The following table summarizes the carrying values, principal amounts and fair values of these instruments as of the periods indicated:

	December 31, 2025			December 31, 2024		
	Carrying Value	Principal Amount	Fair Value	Carrying Value	Principal Amount	Fair Value
Credit Facility[(1)]	$ —	$ —	$ —	$ —	$ —	$ —
5.375% Senior Notes due 2026[(2)]	—	—	—	288,357	289,448	287,400
8.00% Senior Notes due 2027[(2)]	556,453	550,000	557,270	560,910	550,000	561,855
3.25% Convertible Senior Notes due 2028[(2)(3)]	—	—	—	166,803	170,000	436,554
5.875% Senior Notes due 2029[(2)]	671,782	700,000	703,417	664,935	700,000	688,103
9.875% Senior Notes due 2031[(2)]	343,761	325,000	349,642	532,730	500,000	550,562
7.00% Senior Notes due 2032[(2)]	986,174	1,000,000	1,044,656	984,426	1,000,000	1,017,903
6.25% Senior Notes due 2033[(2)]	987,428	1,000,000	1,028,006	986,072	1,000,000	989,508

(1) The carrying values of the amounts outstanding under OpCo's Credit Agreement approximate fair value because its variable interest rates are tied to current market rates and the applicable credit spreads represent current market rates for the credit risk profile of the Company.

(2) The carrying values include associated unamortized debt issuance costs and any debt discounts or premiums as reflected in the consolidated balance sheets. The fair values are determined using quoted market prices for these debt securities, a Level 1 classification in the fair value hierarchy, and are based on the aggregate principal amount of the senior notes outstanding.

(3) The Convertible Senior Notes were redeemed during the year ended December 31, 2025, refer to *Note 5—Long-Term Debt* for additional information.

Note 10—Shareholders' Equity and Noncontrolling Interest

Authorized shares of Common Stock

The Company's stockholders approved the Fifth Amended and Restated Certificate of Incorporation (as amended and restated, the "Charter"), which became effective on May 22, 2024. The Charter, among other things, authorizes 1,000,000,000 shares of Class A Common Stock and 500,000,000 shares of Class C Common Stock for issuance.

Class A Common Stock

The Company had 751,746,410 shares of Class A Common Stock outstanding as of December 31, 2025.

Holders of Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by the Company's stockholders. Holders of the Class A Common Stock and holders of the Class C Common Stock will vote together as a single class on all matters submitted to a vote of the Company's stockholders, except as required by law.

Unless specified in the Charter (including any certificate of designation of preferred stock) or the Company's Second Amended and Restated Bylaws, or as required by applicable provisions of the Delaware General Corporation Law or applicable stock exchange rules, the affirmative vote of a majority of the Company's shares of common stock that are voted is required to approve any such matter voted on by the Company's stockholders. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors. Subject to the rights of the holders of any outstanding series of preferred stock, the holders of the Class A Common Stock are entitled to receive ratable dividends when, as and if declared by the board of directors out of funds legally available therefor.

In the event of a liquidation, dissolution or winding up of the Company, the holders of the Class A Common Stock are entitled to share ratably in all assets remaining available for distribution to them after payment of liabilities and after provision is made for each class of stock, if any, having preference over the Class A Common Stock. The holders of the Class A Common Stock have no preemptive or other subscription rights. There are no sinking fund provisions applicable to the Class A Common Stock.

Class C Common Stock

The Company had 84,378,125 shares of Class C Common Stock outstanding as of December 31, 2025 which were issued in connection with the Colgate and Earthstone mergers.

Holders of Class C Common Stock, together with holders of Class A Common Stock voting as a single class, have the right to vote on all matters properly submitted to a vote of the stockholders. In addition, the holders of Class C Common Stock, voting as a separate class, will be entitled to approve any amendment, alteration or repeal of any provision of the Charter that would alter or change the powers, preferences or relative, participating, optional or other special rights of the Class C Common Stock. Holders of Class C Common Stock will not be entitled to any dividends from the Company and will not be entitled to receive any of the Company's assets in the event of any voluntary or involuntary liquidation, dissolution or winding up of the Company's affairs.

Shares of Class C Common Stock may only be issued to OpCo or unitholders of OpCo, including their respective successors, assignees or any permitted transferees of such unit holders. A holder of Class C Common Stock may transfer shares of Class C Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such holder's Common Units representing common membership interests in OpCo to such transferee in compliance with the Amended and Restated Limited Liability Company Agreement of OpCo. Each holder of Class C Common Stock generally has the right to cause the Company to redeem all or a portion of its Common Units in exchange for, at the Company's option, an equal number of shares of Class A Common Stock or an equivalent amount of cash. The Company may, however, at its option, effect a direct exchange of cash or Class A Common Stock for such Common Units in lieu of such a redemption by OpCo. Upon the future redemption or exchange of Common Units held by a holder of Class C Common Stock, a corresponding number of shares of Class C Common Stock held by such holder of Class C Common Stock will be canceled.

Preferred Stock

The Company is authorized to issue 1,000,000 shares of preferred stock, par value $0.0001 per share, with such designations, voting and other rights and preferences as may be determined from time to time by the Company's board of directors. At December 31, 2025, there were no shares of preferred stock issued or outstanding.

Stock Conversion

During the years ended December 31, 2025, 2024 and 2023, certain legacy owners of Colgate and Earthstone exchanged 13.2 million, 127.6 million and 80.7 million, respectively, of their Common Units of OpCo with the cancellation of a corresponding number of shares of Class C Common Stock, for an equivalent number of shares of Class A Common Stock. A deferred tax liability of $3.5 million and deferred tax assets of $96.7 million and $29.6 million, respectively, were recorded in equity as a result of the conversions of shares from the noncontrolling interest owners for the years ended December 31, 2025, 2024 and 2023, respectively. No cash proceeds were received by the Company in connection with these transactions.

Stock Issuances

During the year ended December 31, 2025, the Company issued 30.6 million shares of Class A Common Stock in connection with the Redemption of its Convertible Senior Notes as discussed in *Note 5—Long-Term Debt.*

During the year ended December 31, 2024, the Company completed an underwritten public offering of 26.5 million shares of its Class A Common Stock in which the Company received net cash proceeds of $402.2 million after underwriting discounts and commissions. The Company used the net proceeds from this equity offering to fund a portion of the aggregate purchase price of the Bolt-On Acquisition discussed in *Note 2—Business Combinations.*

Additionally, during the year ended December 31, 2024, the Company issued 6.2 million shares of Class A Common Stock, which were issued as partial consideration for a portion of an asset acquisition. No cash proceeds were received by the Company in connection with this issuance.

Dividends

The following table summarizes the Company's base and variable dividend per share of Class A Common Stock and distribution per Common Unit (each of which has an underlying share of Class C Common Stock) declared and paid during each period:

	Dividend/Distribution per Share			Total Dividends/Distributions Declared and Paid
	Base	Variable	Total	
Year ended,				**(in thousands)**
December 31, 2025	$ 0.60	$ —	$ 0.60	$ 502,944
December 31, 2024	$ 0.32	$ 0.39	$ 0.71	$ 560,865
December 31, 2023	$ 0.20	$ 0.17	$ 0.37	$ 236,004

Repurchase Program

The Company's Board of Directors authorized a stock repurchase program to acquire up to $1 billion of the Company's outstanding common stock (the "Repurchase Program"), which was approved to run on an indefinite basis and can be used by the Company to reduce its shares of Class A Common Stock and Class C Common Stock outstanding. Repurchases may be made from time to time in the open-market or via privately negotiated transactions at the Company's discretion and will be subject to market conditions, applicable legal requirements, available liquidity, compliance with the Company's debt agreements and other factors. The Repurchase Program does not require any specific number of shares to be acquired and can be modified or discontinued by the Company's Board of Directors at any time.

During the year ended December 31, 2025, the Company paid $46.8 million to repurchase 4.4 million shares of Class A Common Stock at a weighted average price of $10.70 per share as part of the Repurchase Program. During the year ended December 31, 2023, the Company paid $76.0 million to repurchase 6.8 million shares of Class A Common Stock as part of the Repurchase Program. The shares that were repurchased were subsequently canceled by the Company.

Additionally, during the years ended December 31, 2025, 2024 and 2023, the Company paid $26.9 million, $61.0 million and $86.5 million, respectively, to repurchase 2.0 million, 3.8 million and 7.2 million, respectively, Common Units of OpCo resulting in an equal number of associated shares of Class C Common Stock simultaneously being canceled under its Repurchase Program.

Noncontrolling Interest

The noncontrolling interest relates to Common Units that were issued in connection with the Colgate and Earthstone mergers. The noncontrolling interest percentage is affected by various equity transactions such as conversions of Common Units for Class A Common Stock (and corresponding Class C Common Stock cancellations) and transactions involving Class A Common Stock.

As of December 31, 2025, the noncontrolling interest ownership of OpCo had decreased to 10% from 12% as of December 31, 2024 and 30% as of December 31, 2023. These decreases were mainly the result of (i) exchanges of Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock; and (ii) Class C Common Stock repurchases completed by the Company as discussed above.

The Company consolidates the financial position, results of operations and cash flows of OpCo and reflects the portion retained by other holders of Common Units as a noncontrolling interest. Refer to the consolidated statements of shareholders' equity for a summary of the activity attributable to the noncontrolling interest that occurred during the periods presented. Refer to *Note 16—Subsequent Events* regarding a corporate transaction impacting the noncontrolling interest ownership percentage that occurred after the reporting period.

Note 11—Earnings Per Share

Basic EPS is calculated by dividing net income attributable to Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Diluted EPS is calculated by dividing adjusted net income by the weighted average shares of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted EPS calculation consists of (i) unvested equity-based restricted stock and performance stock units, and outstanding stock options, all using the treasury stock method; and (ii) the Company's Class C Common Stock and shares issuable for our Convertible Senior Notes, which were fully redeemed during the year ended December 31, 2025, both using the "if-converted" method, which is net of tax.

The following table reflects the EPS computations for the periods indicated based on a weighted average number of Class A Common Stock outstanding each period:

	Year Ended December 31,		
(in thousands, except per share data)	**2025**	**2024**	**2023**
Net income attributable to Class A Common Stock	$ 935,174	$ 984,701	$ 476,306
Add: Interest on Convertible Senior Notes, net of tax	—	5,182	5,433
Adjusted net income attributable to Class A Common Stock	$ 935,174	$ 989,883	$ 481,739
Basic weighted average shares of Class A Common Stock outstanding	715,772	640,662	349,213
Add: Dilutive effects of Convertible Senior Notes	—	29,408	27,710
Add: Dilutive effects of equity awards	15,203	14,422	12,173
Diluted weighted average shares of Class A Common Stock outstanding	730,975	684,492	389,096
Basic net earnings per share of Class A Common Stock	$ 1.31	$ 1.54	$ 1.36
Diluted net earnings per share of Class A Common Stock	$ 1.28	$ 1.45	$ 1.24

The following table presents shares excluded from the diluted earnings per share calculation for the periods presented as their impact was anti-dilutive:

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Weighted average shares of Class C Common Stock	94,632	144,566	248,511
Convertible Senior Notes	20,922	—	—
Performance stock units	1,006	208	29
Restricted stock	1,322	172	55
Out-of-the-money stock options	261	444	1,260

Note 12—Income Taxes

The Company is subject to U.S. federal, state and local income taxes with respect to its allocable share of any taxable income of OpCo, as well as any stand-alone income generated by the Company. The Company adopted ASU 2023-09 for the period ended December 31, 2025. As prospective adoption was elected by the Company, additional disclosures required under ASU 2023-09, such as the disaggregation of the income tax rate reconciliation and information regarding income taxes paid, are only presented for the year ended December 31, 2025.

Income tax expenses and benefits included in the consolidated statements of operations are detailed below:

(in thousands)	Year Ended December 31, 2025	2024	2023
Current taxes			
Federal	$ 178	$ 47	$ (104)
State	(1,399)	1,276	2,893
Total current tax expense	(1,221)	1,323	2,789
Deferred taxes			
Federal	254,602	281,513	132,039
State	30,798	17,506	21,117
Total deferred tax expense	285,400	299,019	153,156
Total income tax expense	$ 284,179	$ 300,342	$ 155,945

Reconciliations of the statutory federal income tax expense, which are calculated at the federal statutory rate of 21%, to the income tax expense from continuing operations are provided in the tables below:

($ in thousands)	Year Ended December 31, 2025 Amount	Percent
Income tax expense at the U.S. Federal Statutory rate	$ 290,454	21.0 %
State income tax, net of federal income tax effect[1]	28,605	2.1 %
Noncontrolling interest in partnership	(32,942)	(2.4)%
Tax credits	(90,082)	(6.5)%
Nontaxable or nondeductible items	12,988	0.9 %
Changes in unrecognized tax benefits	84,267	6.1 %
Others adjustments	(9,111)	(0.7)%
Income tax expense	$ 284,179	20.5 %

(1) State taxes in New Mexico and Texas make up the majority (greater than 50%) of the tax effect in this category.

(in thousands)	Year Ended December 31, 2024	2023
Income tax expense at the U.S. Federal Statutory rate	$ 325,679	$ 217,486
State income tax, net of federal income tax effect	20,600	18,741
Noncontrolling interest in partnership	(55,820)	(83,690)
Nondeductible stock-based and other compensation	(3,604)	963
Nondeductible expenses and other	13,487	2,445
Income tax expense	$ 300,342	$ 155,945

Income taxes (net of refunds) were paid in the following jurisdictions:

(in thousands)	Year Ended December 31, 2025
Federal	$ 268
State	(1,080)
Total Current:	$ (812)

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities, which are presented net in the line item *Deferred income taxes* on the Company's consolidated balance sheet, are presented below:

(in thousands)	December 31, 2025	December 31, 2024
Deferred tax assets:		
Net operating loss carryforwards	$ 266,321	$ 260,881
Tax credits	59,255	—
Other assets	268	245
Total deferred tax assets	325,844	261,126
Deferred tax liabilities:		
Investment in OpCo	(1,219,301)	(863,499)
Valuation allowance	(6)	(6)
Net deferred tax liability	$ (893,463)	$ (602,379)

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into law. OBBBA included multiple provisions applicable to U.S. income taxes for businesses of which those with the most significant impact to the Company include the reinstatement of 100% bonus depreciation for certain capital expenditures and allowing deduction for intangible drilling costs for purposes of computing the corporate alternative minimum tax. The effects of changes in tax law are recognized in the period of enactment, and as a result, OBBBA is currently recognized in the Company's condensed consolidated financial statements but did not have a material impact on the Company's effective tax rate for the year ended December 31, 2025.

As of December 31, 2025, the Company had approximately $1.2 billion and $216.1 million of U.S. federal and state net operating loss carryovers, respectively. None of the state net operating loss carryover expires and approximately $302.6 million of the U.S. federal net operating loss carryover expires in 2037. In addition, the Company has approximately $56.7 million and $2.6 million of federal and state general business credit carryovers, respectively. The general business credit carryovers will begin to expire in 2044.

The Company periodically assesses whether it is more-likely-than-not that it will generate sufficient taxable income to realize its deferred income tax assets. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. The Company is projecting future taxable income exclusive of reversing items. Based upon these earnings and the expected timing of the reversal of its existing taxable temporary differences, management determined it is more-likely-than-not that, with the exception of certain state net operating loss carryovers, the remaining deferred income tax assets existing at December 31, 2025 will be realized.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon the examination by the Internal Revenue Service or other governmental agency. As of December 31, 2025, the Company had accrued an unrecognized tax benefits ("UTB") of $84.3 million, which would reduce the Company's effective tax rate in future periods if and when recognized. The timing as to when the Company will substantially resolve the uncertainties associated with its UTB is currently unknown. Interest and penalties related to the UTB, if any, are reported in *Income tax expense* in the consolidated statements of operations. During the year ended December 31, 2025, there were no interest or penalties incurred.

The following table summarizes changes in the balance of the Company's UTB during the periods presented:

(in thousands)	December 31, 2025	December 31, 2024	December 31, 2023
Balance at beginning of period	$ —	$ —	$ —
Additions for tax positions of current period	56,838	—	—
Adjustments for tax positions of prior periods	27,429	—	—
Balance at end of period	$ 84,267	$ —	$ —

The Company is subject to the following material taxing jurisdictions: U.S., Colorado, New Mexico, and Texas. As of December 31, 2025, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2021 through 2024.

Note 13—Commitments and Contingencies

Contractual Obligations

The following table is a schedule of the Company's future minimum payments required under contractual commitments that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2025**:**

(in thousands)	2026	2027	2028	2029	2030	Thereafter	Total
Purchase obligations	$ 50,507	$ 15,251	$ 13,233	$ 724	$ —	$ —	$ 79,715
Firm Transportation	28,885	78,282	107,169	118,033	118,032	769,179	1,219,580
Total	$ 79,392	$ 93,533	$ 120,402	$ 118,757	$ 118,032	$ 769,179	$1,299,295

Purchase Obligations

The Company has multi-year energy purchase agreements in place to buy electricity utilized in its operations. Under the contracts, the Company is obligated to purchase a minimum amount of electricity at a fixed price. If the Company does not utilize the minimum amounts of electricity on a monthly basis, the Company is then liable to pay the difference between the fixed price per the agreement and the price at which the supplier is able to sell the unutilized quantity. The total remaining obligation is $41.0 million, which represents the gross minimum financial commitments pursuant to these agreements as of December 31, 2025. The Company paid electricity costs of $32.9 million, $10.2 million and $7.5 million for the years ended December 31, 2025, 2024 and 2023, respectively, to these suppliers.

The Company has an agreement in place to buy frac sand used in its well fracture stimulation process that has a contract term through December 31, 2026. Under the terms of this take-or-pay agreement, the Company is obligated to purchase a minimum volume of frac sand at a fixed price. The remaining obligation under this contract is $38.7 million, which represents the minimum financial commitment pursuant to the terms of the contract from December 31, 2025 through December 31, 2026. Actual expenditures under these contracts may exceed the minimum commitments. The Company paid $132.2 million, $147.2 million and $102.5 million for the years ended December 31, 2025, 2024 and 2023, respectively, under the original contract, which was capitalized as incurred during the periods.

Firm Transportation

During the year ended December 31, 2025, the Company entered into a series of firm commitment transportation agreements that guarantee volumetric capacity on pipelines for gas transportation with varying terms over ten years. The agreements are effective beginning in 2025 and will provide the Company natural gas capacity on the pipelines ranging from 25,000 to 300,000 MMBtu per day. The Company is not required to deliver natural gas volumes specifically produced from any of the Company's properties under these agreements. The agreements include demand fees that are applied to the total volumetric capacity per the agreements regardless if utilized. As a result, the aggregate minimum financial commitment amount over the term of these agreements is approximately $1.2 billion based upon the volumetric commitments per the agreements as of December 31, 2025. The Company has paid $5.8 million related to these commitments during the year ended December 31, 2025, which are included in the Purchased gas sales, net line item described in *Note 14—Revenues*.

Delivery Commitments

In 2024, the Company assumed NGL and natural gas delivery commitments in connection with acquisitions completed during the year. The NGL agreement includes a commitment to deliver a minimum of 9,000 Bbls per day of NGL volumes to the purchaser over the next 2.3 years or be subject to under-delivery fees equal to a specified rate under the contractual required minimum volumes, subject to inflation factors. The natural gas delivery commitments include a commitment to deliver certain minimum daily volumes of natural gas over the next 6 years or be subject to under-delivery fees equal to a specified rate, subject to inflation factors. The aggregate minimum financial commitment amounts over the remaining term for the NGL and natural gas agreements are $24.8 million and $61.5 million, respectively.

The amount discussed above represent the total gross volumes the Company is required to deliver per these agreements, which gross volumes are not comparable to the Company's net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation,* as amounts therein are reflected net of all royalties, overriding royalties and production due to others. During the year ended December 31, 2025, the Company incurred $12.2 million of under-delivery charges related to these agreements. The Company may incur additional under-delivery penalties related to these agreements during the remaining 2.3 and 6 year terms, however, based upon current projections of expected production, the Company does not believe future charges would be material to the Company's financial position, results of operations or cash flows.

Lease Commitments

Refer to *Note 15—Leases* for details on the Company's operating and finance lease agreements.

Contingencies

The Company may at times be subject to various commercial or regulatory claims, prior period adjustments from service providers, litigation or other legal proceedings that arise in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, management believes it is remote that the impact of such matters that are reasonably possible to occur will have a material adverse effect on the Company's financial position, results of operations or cash flows. Management is unaware of any pending litigation brought against the Company requiring a contingent liability to be recognized as of the date of these consolidated financial statements.

Note 14—Revenues

Revenue from Contracts with Customers

Crude oil, NGL and natural gas sales are recognized at the point that control of the product is transferred to the customer and collectability is reasonably assured. Substantially all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, transportation costs to an active spot market and quality differentials. As a result, the Company's realized prices of oil, NGLs and natural gas fluctuate to remain competitive with other available oil, NGLs and natural gas supplies both globally and locally.

Oil and gas revenues presented within the consolidated statements of operations relate to the sale of oil, NGLs and natural gas as shown below:

	Year Ended December 31,		
	2025	2024	2023
Operating revenues (in thousands):			
Oil sales	$ 4,251,193	$ 4,362,965	$ 2,696,777
NGL sales	658,515	637,529	282,039
Natural gas sales	131,663	240	142,077
Purchased gas sales, net	23,840	—	—
Oil and gas sales	$ 5,065,211	$ 5,000,734	$ 3,120,893

Oil sales

The Company's crude oil sales contracts are generally structured whereby oil is delivered to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes title of the product. This delivery point is usually at the wellhead or at the inlet of a transportation pipeline. Revenue is recognized when control transfers to the purchaser at the delivery point based on the net price received from the purchaser. Any downstream transportation costs incurred by crude purchasers are reflected as a net reduction to oil sales revenues.

NGL and Natural gas sales

Under the Company's natural gas processing contracts, liquids rich natural gas is delivered to a midstream gathering and processing entity at the agreed upon delivery point at which the purchaser takes title of the product. The midstream processing entity gathers and processes the raw gas and then remits proceeds to the Company. For these contracts, the Company evaluates when control is transferred and revenue should be recognized. Where the Company elects to take its NGL or residue gas product "in-kind" at the plant tailgate, fees incurred prior to transfer of control at the outlet of the plant are presented as *GP&T* within the consolidated statements of operations. Where the Company does not take its NGL or residue gas products "in-kind", transfer of control occurs at the inlet of the gas gathering systems, or prior, and fees incurred subsequent to this point are reflected as a net reduction to NGL and natural gas sales revenues presented in the table above.

Purchased gas sales

The Company has entered into a series of natural gas purchase and sale agreements to facilitate the sale of natural gas at additional markets. The proceeds and costs of these transactions are presented net as they are transacted with the same counterparty (or same related parties) as shown in the line item Purchased gas sales, net in the table above.

Performance obligations

For all commodity products, the Company records revenue in the month production is delivered to the purchaser. Settlement statements for crude oil are generally received within 30 days following the date that production volumes are delivered, but for NGL and natural gas sales, statements may not be received for 30 to 60 days after delivery has occurred. However, payment is unconditional once the performance obligations have been satisfied. At such time, the volumes delivered and sales prices can be reasonably estimated and amounts due from customers are accrued in *Accounts receivable, net i*n the consolidated balance sheets. As of December 31, 2025 and 2024, such receivable balances were $435.0 million and $326.4 million, respectively.

The Company records any differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Historically, any identified differences between revenue estimates and actual revenue received have not been significant. For the years ended December 31, 2025 and 2024, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods were not material.

Transaction price allocated to remaining performance obligations

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606, *Revenue from contracts with Customers,* which states the Company is not required to disclose the transaction price allocated to the remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, monthly sales of a product generally represent a separate performance obligation. Therefore, future commodity volumes to be delivered and sold are wholly unsatisfied, and disclosure of the transaction price allocated to such unsatisfied performance obligations is not required.

Note 15—Leases

At contract inception, the Company determines whether or not an arrangement contains a lease. Upon determination of a lease, a lease right-of-use ("ROU") asset and related liability are recorded based on the present value of the future lease payments over the lease term. ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make future lease payments arising from the lease.

The Company has operating leases for drilling rig contracts, office rental agreements and other wellhead equipment. As of December 31, 2025, these leases have remaining lease terms ranging from one month to six years, some of which include options to extend the lease term for up to five years, and some of which include options to terminate prior to the end of the contractual lease term. These options are considered in determining the lease term and are included in the present value of future payments that are recorded for leases when the Company is reasonably certain to exercise the option. The Company has one finance lease that was entered into in connection with an office building purchase in Midland, Texas. As part of the building purchase, the Company assumed a ninety-nine year ground lease and accordingly, recorded a finance lease liability. Leases with an initial term of one year or less are not recorded in the consolidated balance sheets. Additionally, none of the Company's lease agreements contain any material residual value guarantees or material restrictive covenants.

The following table provides additional information related to the Company's lease assets and liabilities as presented on balance sheet for the periods presented:

(in thousands)	Balance Sheet Classification	December 31, 2025	December 31, 2024
Assets			
Operating right-of-use assets	Operating lease right-of-use asset	$ 132,764	$ 119,703
Finance right-of-use asset	Other noncurrent assets	14,877	15,033
Liabilities			
Current			
Operating lease liabilities	Operating lease liabilities	$ 79,496	$ 57,216
Finance lease liability	Other current liabilities	791	772
Noncurrent			
Operating lease liabilities	Operating lease liabilities	$ 55,102	$ 64,288
Finance lease liability	Other noncurrent liabilities	15,522	15,168

The present value of future lease payments is determined at the lease commencement date based upon the Company's incremental borrowing rate. The incremental borrowing rate is calculated using a risk-free interest rate adjusted for the Company's specific risk and the specific lease term. The table below summarizes the Company's weighted average discount rate and weighted-average remaining lease term as of the periods presented.

	December 31, 2025		December 31, 2024	
	Operating Leases	Finance Lease	Operating Leases	Finance Lease
Weighted-average discount rate	6.89 %	7.3 %	6.04 %	7.3 %
Weighted-average remaining lease term (years)	2.10	95.25	2.59	96.25

The Company's drilling rig contracts, office rental agreements and wellhead equipment agreements contain both lease and non-lease components, which are combined and accounted for as a single lease component.

Variable lease payments are recognized in the period in which they are incurred and include operating expenses related to the office rental agreements. Expenses related to short-term leases are recognized on a straight-line basis over the lease term as either expenses to the consolidated statements of operations or capitalized to the consolidated balance sheets. The following table presents the components of the Company's lease expenses for the periods presented.

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Operating lease costs		
Operating lease cost	$ 111,918	$ 80,135
Variable lease cost	18,004	3,156
Short-term lease cost	263,407	242,549
Finance lease costs		
Amortization of ROU assets	156	156
Interest on lease liabilities	1,176	1,149
Total lease Cost	$ 394,661	$ 327,145

The following table presents supplemental cash flow information related to the Company's leases for the periods presented.

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Operating lease liability payments:		
Net cash used in operating activities	$ 43,850	$ 31,026
Net cash used in investing activities	68,068	49,109
Finance lease liability payments:		
Net cash used in operating activities	803	783
Right-of-use assets recognized (derecognized) with offsetting operating lease liabilities	83,838	113,758

Maturities of the Company's long-term operating and finance lease liabilities by fiscal year as of December 31, 2025 are as follows:

(in thousands)	**Operating Leases[(1)]**	**Finance Lease**
2026	$ 82,790	$ 823
2027	40,462	843
2028	12,194	864
2029	2,483	886
2030	2,202	908
2031 and thereafter	1,885	204,626
Total lease payments	142,016	208,950
Less: imputed interest	(7,418)	(192,637)
Present value of lease liabilities	$ 134,598	$ 16,313

(1) Total operating lease payments exclude variable lease payments which can be charged under the terms of the lease agreements.

Note 16—Subsequent Events

Corporation Reorganization

On January 7, 2026, the Company completed a corporate reorganization pursuant to which we, among other things, reorganized under a new public holding company (the "Reorganization"). In connection with the Reorganization, the public holding company prior to the Reorganization became a wholly owned subsidiary of the new public holding company, which, following completion of the Reorganization, changed its name to "Permian Resources Corporation," became the successor issuer of the prior public holding company and replaced the prior public holding company as the company trading on the NYSE, with shares of Class A Common Stock continuing to trade on the NYSE on an uninterrupted basis.

Additionally, certain shareholders surrendered 48.9 million shares of Class C Common Stock to the Company for no value, which shares were subsequently canceled, and thereafter contributed the corresponding underlying Common Units of OpCo to the new public holding company in exchange for newly issued shares of its Class A Common Stock. No Class A Common Stock or Class C Common Stock was sold as part of these transactions, and the aggregate amount of Common Stock outstanding remained the same following the Reorganization as all other existing Common Stock of the Company was exchanged for corresponding equity of the new public holding company on a one-for-one basis. There were no changes to the Company's board of directors, executive officers, operations, name or public company trading following the Reorganization.

The Reorganization was completed in an effort, among other things, to simplify the Company's current equity structure. Following the Reorganization, approximately 35.5 million shares of Class C Common Stock remain outstanding, reducing the Company's noncontrolling interest ownership of OpCo to approximately 4%. There will be no impact to the Company's consolidated financial statement totals as a result of the Reorganization; however, the noncontrolling interest portion of the Company's total equity will be reduced which will have an associated deferred tax liability.

Dividends Declared

On February 25, 2026, the Company announced that its Board of Directors declared a quarterly base dividend of $0.16 per share of Class A Common Stock and distribution of $0.16 per share of Class C Common Stock (each of which has an underlying Common Unit of OpCo). The quarterly base dividend represents an increase from the $0.15 per share dividend paid each quarter during the year ended December 31, 2025. The dividend is payable March 31, 2026, to shareholders of record as of March 17, 2026.

Supplemental Information About Oil & Natural Gas Producing Activities (Unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Proved properties	$ 21,484,903	$ 18,595,780
Unproved properties	1,933,409	1,990,441
Total proved and unproved properties	23,418,312	20,586,221
Accumulated depreciation, depletion and amortization	(7,168,925)	(5,163,124)
Net capitalized costs	$ 16,249,387	$ 15,423,097

Costs Incurred for Oil and Natural Gas Producing Activities

The costs incurred in the Company's oil and gas production, exploration, and development activities are displayed in the table below and include costs whether capitalized or expensed as well as revisions and additions to the estimated future asset retirement obligations.

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Acquisition costs:			
Proved properties[(1)]	$ 567,919	$ 894,603	$ 4,590,212
Unproved properties[(1)]	513,268	264,114	1,147,857
Development costs[(2)]	1,811,551	1,903,950	1,596,657
Exploration costs[(3)]	18,648	20,373	17,537
Total	$ 2,911,386	$ 3,083,040	$ 7,352,263

(1) Amounts include the fair value of the proved and unproved properties recorded in the purchase price allocation with respect to business combinations and asset acquisitions transacted during each period. These purchases were funded through a combination of issuances of the Company's Class A and C Common Stock, debt assumed and cash. Additionally, for the year ended December 31, 2023, this includes deferred tax liabilities of $344.2 million assumed in the Earthstone Merger and other asset acquisitions. Refer to *Note 2—Business Combinations* for additional information on these transactions.

(2) Includes the cost of drilling development wells and associated facilities for which construction was completed during the period. Costs associated with wells and facilities that are in progress or awaiting completion at year-end are not included and were $542.2 million, $398.9 million and $242.4 million as of the years ended December 31, 2025, 2024 and 2023, respectively.

(3) Includes all exploratory expenses, including dry hole costs. Does not include other operating expenses.

Estimated Quantities of Proved Oil and Gas Reserves

The reserve estimates presented below and included herein conform to the definitions prescribed by the SEC. The Company retained Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, to prepare the estimates of all of its proved reserves as of December 31, 2025, 2024 and 2023 and their related pre-tax future net cash flows. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC.

As of December 31, 2025, all of the Company's oil and gas reserves are attributable to properties within the United States. The table below presents a summary of changes in quantities of proved oil and gas reserves in the Company's estimated proved reserves:

	Crude Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)(2)
Total proved reserves:				
Balance - December 31, 2022	287,032	122,851	1,033,571	582,146
Extensions and discoveries	44,878	18,391	126,646	84,376
Revisions to previous estimates	(39,725)	(9,038)	(120,624)	(68,868)
Purchases of reserves in place	139,938	121,342	848,391	402,678
Divestitures of reserves in place	(3,227)	(563)	(2,712)	(4,242)
Production	(35,560)	(15,569)	(119,182)	(70,992)
Balance - December 31, 2023	393,336	237,414	1,766,090	925,098
Extensions and discoveries	115,542	46,735	330,679	217,390
Revisions to previous estimates	(30,335)	(9,659)	(106,419)	(57,730)
Purchases of reserves in place	41,884	14,962	90,917	71,999
Divestitures of reserves in place	(2,970)	(498)	(3,616)	(4,070)
Production	(58,276)	(30,636)	(220,900)	(125,730)
Balance - December 31, 2024	459,181	258,318	1,856,751	1,026,957
Extensions and discoveries	110,932	56,446	367,486	228,626
Revisions to previous estimates	(43,672)	7,123	(2,037)	(36,889)
Purchases of reserves in place	19,133	9,286	74,976	40,915
Production	(66,364)	(35,773)	(247,045)	(143,311)
Balance - December 31, 2025	479,210	295,400	2,050,131	1,116,298
Proved developed reserves:				
December 31, 2023	271,328	192,368	1,441,914	704,015
December 31, 2024	312,641	196,775	1,422,468	746,494
December 31, 2025	327,545	215,469	1,506,487	794,095
Proved undeveloped reserves:				
December 31, 2023	122,008	45,046	324,176	221,083
December 31, 2024	146,540	61,543	434,283	280,463
December 31, 2025	151,665	79,931	543,644	322,203

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Includes total proved reserves of 112,652 MBoe, 127,319 MBoe and 277,529 MBoe, respectively, as of December 31, 2025, 2024 and 2023 attributable to a consolidated subsidiary in which there was a 10%, 12% and 30%, respectively, noncontrolling interest.

Notable changes in proved reserves for the year ended December 31, 2025 included the following:

- *Extensions and discoveries.* In 2025, 228.6 MMBoe of proved reserves were added through extensions and discoveries and include: i) 142.7 MMBoe for new proved undeveloped ("PUD") reserves; and ii) 85.9 MMBoe for unproved locations that were successfully converted to new proved developed ("PDP") wells during the period. These additions resulted from the Company's continuous drilling program, which added locations primarily in the various Bone Spring and Wolfcamp formations on the Company's acreage in the Permian Basin.
- *Purchases of reserves in place.* In 2025, 40.9 MMBoe of proved reserves were added from properties acquired in asset acquisitions completed throughout 2025. Refer to *Note 3—Acquisitions and Divestitures* for further details on these transactions.
- *Revisions to previous estimates.* Total revisions to previous estimates reduced proved reserves 36.9 MMBoe during 2025. These downward revisions primarily related to i) 36.0 MMBoe of negative revisions associated with PUD locations that were reclassified to unproved reserves or removed due to changes in the Company's development plan; and ii) 26.3 MMBoe of reduced reserves from lower average commodity prices for the year ended 2025. These downward revisions were partially offset by 25.4 MMBoe of positive revisions primarily related to higher estimates associated with timing and performance.

Notable changes in proved reserves for the year ended December 31, 2024 included the following:

- *Extensions and discoveries.* In 2024, 217.4 MMBoe of proved reserves were added through extensions and discoveries and include: i) 121.8 MMBoe for new PUD locations; and ii) 95.6 MMBoe for unproved locations that were successfully converted to new PDP wells during the period. These additions resulted from the Company's continuous drilling program, which added locations primarily in the various Bone Spring and Wolfcamp formations on the Company's acreage in the Permian Basin.
- *Purchases of reserves in place.* In 2024, 72.0 MMBoe of proved reserves were added from properties acquired in the Bolt-On Acquisition and other asset acquisitions completed throughout 2024. Refer to *Note 2—Business Combinations* and *Note 3—Acquisitions and Divestitures* for further details on these transactions.
- *Revisions to previous estimates.* Total revisions to previous estimates reduced proved reserves 57.7 MMBoe during 2024. These downward revisions primarily related to i) 29.6 MMBoe of negative revisions associated with PUD locations that were reclassified to unproved reserves or removed due to changes in the Company's development plan, ii) 17.0 MMBoe of reduced reserves from lower average commodity prices for the year ended 2024 and iii) 11.1 MMBoe of net downward revisions primarily related to lowered estimates associated with timing and performance.

Notable changes in proved reserves for the year ended December 31, 2023 included the following:

- *Purchases of reserves in place.* In 2023, 402.7 MMBoe of proved reserves were added primarily from properties acquired in the Earthstone Merger on November 1, 2023. Refer to *Note 2—Business Combinations* for further details on the Earthstone Merger transaction.
- *Extensions and discoveries.* In 2023, 84.4 MMBoe of proved reserves were added through extensions and discoveries and include: i) 47.9 MMBoe for new PUD locations; and ii) 36.4 MMBoe for unproved locations that were successfully converted to new PDP wells during the period. These additions resulted from the Company's 2023 drilling program, which added locations primarily in the various Bone Spring and Wolfcamp formations on the Company's acreage in the Delaware Basin.
- *Revisions to previous estimates.* In 2023, total revisions to previous estimates reduced proved reserves 68.9 MMBoe. These downward revisions in 2023 were primarily related to i) 25.4 MMBoe of reduced reserves from lower average commodity prices for the year ended 2023, ii) 22.3 MMBoe of negative revisions associated with PUD locations that were mainly reclassified to unproved reserves due to changes in the Company's development plan, and iii) the 21.2 MMBoe of downward revisions primarily related to lowered estimates associated with timing and performance.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows (the "Standardized Measure") relating to proved oil and gas reserves has been prepared in accordance with FASB ASC Topic 932, *Extractive Activities - Oil and Gas* ("ASC 932"). Future cash inflows as of December 31, 2025, 2024 and 2023 have been computed by applying average fiscal year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month periods ended December 31, 2025, 2024 and 2023, respectively) to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves, based on year-end costs and assuming the continuation of existing economic conditions. The Standardized Measure also includes costs for future dismantlement, abandonment and rehabilitation obligations.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves.

Future net cash flows are discounted at a rate of 10% annually to derive the Standardized Measure. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

The following table presents the Company's Standardized Measure of discounted future net cash flows:

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Future cash inflows	$ 38,611,475	$ 40,157,175	$ 39,110,246
Future development costs	(4,253,827)	(4,037,158)	(3,542,036)
Future production costs	(18,026,302)	(16,715,475)	(15,772,824)
Future income tax expenses	(1,787,484)	(2,620,733)	(2,629,285)
Future net cash flows	14,543,862	16,783,809	17,166,101
10% discount to reflect timing of cash flows	(6,178,359)	(7,441,476)	(7,639,884)
Standardized measure of discounted future net cash flows[1]	$ 8,365,503	$ 9,342,333	$ 9,526,217

(1) Includes discounted future net cash flows of $844.2 million as of December 31, 2025, $1.2 billion as of December 31, 2024 and $2.9 billion as of December 31, 2023 attributable to a consolidated subsidiary in which there was a 10%, 12% and 30%, respectively, noncontrolling interest.

The following summarizes the principal sources of change in the Standardized Measure of discounted future net cash flows and such changes have been computed in accordance with ASC 932:

(in thousands)	Year Ended December 31, 2025	2024	2023
Standardized measure of discounted future net cash flows, beginning of period	$ 9,342,333	$ 9,526,217	$ 9,425,578
Sales of oil, NGLs and natural gas, net of production costs	(3,697,894)	(3,754,229)	(2,417,077)
Purchase of minerals in place	400,029	877,604	5,272,706
Divestiture of minerals in place	—	(47,188)	(81,196)
Extensions and discoveries, net of future development costs	2,100,129	2,332,025	1,173,711
Previously estimated development costs incurred during the period	840,969	815,176	856,033
Net change in prices and production costs	(2,106,645)	(1,139,162)	(5,966,081)
Change in estimated future development costs	271,065	283,447	244,751
Revisions of previous quantity estimates	(367,636)	(711,074)	(823,441)
Accretion of discount	1,083,043	1,110,773	1,171,468
Net change in income taxes	414,285	93,418	707,586
Net change in timing of production and other	85,825	(44,674)	(37,821)
Standardized measure of discounted future net cash flows, end of period(1)	$ 8,365,503	$ 9,342,333	$ 9,526,217

(1) Includes discounted future net cash flows of $844.2 million as of December 31, 2025, $1.2 billion as of December 31, 2024 and $2.9 billion as of December 31, 2023 attributable to a consolidated subsidiary in which there was a 10%, 12% and 30%, respectively, noncontrolling interest.

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate weighted average sales prices (inclusive of adjustments for transportation, quality and basis differentials) for each of the periods indicated below as follows:

	Year Ended December 31, 2025	2024	2023
Oil (per Bbl)	$ 64.69	$ 74.46	$ 77.05
NGLs (per Bbl)	20.58	22.11	24.95
Gas (per Mcf)	0.75	0.14	1.63

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, the Company has evaluated, under the supervision and with the participation of management, including the principal executive officers and principal financial officer, the effectiveness of the design and operation of disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2025. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports that the Company files under the Exchange Act is accumulated and communicated to management, including the principal executive officers and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC.

The principal executive officers and principal financial officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2025 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in the system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including the principal executive officers and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2025, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that the Company's internal control over financial reporting was effective as of December 31, 2025.

This Annual Report includes an attestation report of KPMG LLP, the Company's independent registered public accounting firm, on the Company's internal control over financial reporting as of December 31, 2025, which is included in this Annual Report.

ITEM 9B. OTHER INFORMATION

Trading Plans

During the quarter ended December 31, 2025, no directors or officers, as defined in Rule 16a-1(f), adopted or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement," each as defined in Regulation S-K Item 408.

Second Amended and Restated Bylaws

On February 23, 2026, the Company's board of directors approved the Company's Second Amended and Restated Bylaws (as amended and restated, the "Bylaws"), effective as of such date. Among other matters, the Bylaws (i) provide that stockholder lists no longer need to be made available during a meeting of stockholders, (ii) update when notice need not be given for an adjourned stockholder meeting, (iii) clarify that materials attached to, or enclosed with, notice to stockholders are deemed to be part of such notice, (iv) revise procedures and disclosure requirements for stockholder nominations to address Rule 14a-19 of the Exchange Act, (v) make certain clarifications and updates to the advance notice and director nomination procedures and the requirements for a proper stockholder's notice, (vi) revise notice procedures, in line with market practice, for giving notice to stockholders, the Company and directors, (vii) allow stockholder action by written consent if approved by the board of directors in advance of taking such action and (viii) make other administrative, modernizing, clarifying and conforming changes.

The foregoing description of the Bylaws does not purport to be complete and is qualified in its entirety by reference to the full text of the Bylaws, a copy of which is filed hereto as Exhibit 3.2 and incorporated by reference herein.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Dallas, Texas, Auditor Firm ID: 185.

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

Exhibit Number	Description of Exhibits
2.1	Business Combination Agreement, dated as of May 19, 2022, by and among Registrant, Centennial Resource Production, LLC, Colgate Energy Partners III, LLC, among other parties (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on May 19, 2022).
2.2	Agreement and Plan of Merger, dated as of August 21, 2023, among Permian Resources Corporation, Smits Merger Sub I Inc., Smits Merger Sub II LLC, Permian Resources Operating, LLC, Earthstone Energy, Inc. and Earthstone Energy Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on August 21, 2023).
2.3	Master Reorganization Agreement, dated as of December 22, 2025, by and among Permian Resources Corporation (n/k/a Permian Resources Holdings Inc.), Permian Resources Operating, LLC, PRC NewCo Inc (n/k/a Permian Resources Corporation) and PRC NewCo II Inc (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 22, 2025).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2026).
3.2*	Second Amended and Restated Bylaws.
3.3	Eighth Amended and Restated Limited Liability Company Agreement of Permian Resources Operating, LLC dated as of January 7, 2026 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2026).
4.1	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
4.2*	Description of Company's Common Stock.
4.3	Indenture (5.875% Senior Notes due 2029), dated as of June 30, 2021, among Colgate Energy Partners III, LLC, the guarantors party thereto and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.14 to the Company's Annual Report on Form 10-K filed with the SEC on February 24, 2023).
4.4	First Supplemental Indenture (5.875% Senior Notes due 2029), dated as of September 1, 2022, among Centennial Resource Production, LLC, Colgate Energy Partners III, LLC, the guarantors party thereto and Computershare Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the SEC on September 8, 2022).
4.5	Second Supplemental Indenture (5.875% Senior Notes due 2029), dated as of September 5, 2023, among Permian Resources Operating, LLC, the guarantors party thereto and Computershare Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed with the SEC on September 5, 2023).
4.6	Third Supplemental Indenture (5.875% Senior Notes due 2029), dated as of November 1, 2023, among Permian Resources Operating, LLC, the guarantors party thereto and Computershare Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the SEC on November 3, 2023).
4.7	Indenture (8.00% Senior Notes due 2027), date as of April 12, 2022, among Earthstone Energy Holdings, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Earthstone Energy Inc.'s Current Report on Form 8-K filed with the SEC on April 13, 2022.
4.8	Second Supplemental Indenture (8.000% Senior Notes due 2027), dated as of November 1, 2023, among Permian Resources Operating, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Company's Current Report on Form 8-K filed with the SEC on November 3, 2023).
4.9	Indenture (9.875% Senior Notes due 2031), dated as of June 30, 2023, among Earthstone Energy Holdings, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Earthstone Energy Inc.'s Current Report on Form 8-K filed with the SEC on June 30, 2023).

4.10	Second Supplemental Indenture (9.875% Senior Notes due 2031), dated as of November 1, 2023, among Permian Resources Operating, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.8 to the Company's Current Report on Form 8-K filed with the SEC on November 3, 2023).
4.11	Indenture (7.000% Senior Notes due 2032), dated as of September 12, 2023, among Permian Resources Operating, LLC, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on September 12, 2023).
4.12	First Supplemental Indenture (7.000% Senior Notes due 2032), dated as of November 1, 2023, by and among Permian Resources Operating, LLC, the guarantors party thereto and Computershare Trust Company, N.A., as Trustee (incorporated reference to Exhibit 4.6 to the Company's Current Report on Form 8-K filed with the SEC on November 3, 2023).
4.13	Indenture (6.25% Senior Notes due 2033), dated as of August 5, 2024, among Permian Resources Operating, LLC, the guarantors named therein and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on August 8, 2024).
10.1	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2026).
10.2	Purchase and Sale Agreement, dated as of August 2, 2018, between Centennial Resource Production, LLC and BP Products North America Inc. (incorporated by reference to Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on August 6, 2018).
10.3	Amendment no. 1 to Purchase and Sale Agreement, dated as of August 2, 2018, by and between Centennial Resource Production, LLC and BP Products North America Inc. (incorporated by reference to Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on April 1, 2020).
10.4#	Form of Stock Option Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.5#	Form of Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.6#	Form of Restricted Stock Agreement under the Permian Resources Corporation 2023 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed with the SEC on August 7, 2025).
10.7#	Form of Amended and Restated Performance Restricted Stock Unit Agreement under the Permian Resources Corporation 2023 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed with the SEC on February 29, 2024).
10.8#	Form of Amended and Restated Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed with the SEC on August 7, 2024).
10.9#	Permian Resources Corporation Third Amended and Restated Severance Plan (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q filed with the SEC on November 11, 2022).
10.10	Permian Resources Corporation Eighth Amended and Restated Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 28, 2025).
10.11#	Centennial Resource Development, Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019).
10.12	Base Capped Call Transaction, dated as of March 16, 2021, between Centennial Resource Production, LLC, Centennial Resource Development, Inc, and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 19, 2021).
10.13	Base Capped Call Transaction, dated as of March 16, 2021, between Centennial Resource Production, LLC, Centennial Resource Development, Inc, and Mizuho Markets Americas LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on March 19, 2021).
10.14	Base Capped Call Transaction, dated as of March 16, 2021, between Centennial Resource Production, LLC, Centennial Resource Development, Inc, and Royal Bank of Canada (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on March 19, 2021).
10.15#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 5, 2022).
10.16#	Form of Performance Restricted Stock Unit Agreement under the Permian Resources Corporation 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K filed with the SEC on February 24, 2023).
10.17	Third Amended and Restated Credit Agreement, dated as of February 18, 2022, among Centennial Resource Production, LLC, Centennial Resource Development, Inc., JPMorgan Chase Bank, N.A. and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on February 23, 2022).
10.18	Limited Consent and Waiver and First Amendment to Third Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on July 21, 2022).

10.19	Third Amendment to Third Amended and Restated Credit Agreement, dated as of April 24, 2023 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on April 28, 2023).
10.20	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of September 1, 2023 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on September 5, 2023).
10.21	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of September 1, 2023 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the SEC on September 5, 2023).
10.22	Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of December 20, 2023 (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K filed with the SEC on February 29, 2024).
10.23	Seventh Amendment to Third Amended and Restated Credit Agreement, dated as of April 25, 2024 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 1, 2024).
10.24	Eighth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2024 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on November 6, 2024).
10.25	Ninth Amendment to Third Amended and Restated Credit Agreement, dated as of April 30, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 6, 2025).
10.26	Tenth Amendment to Third Amended and Restated Credit Agreement, dated as of October 24, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on October 30, 2025).
10.27	Eleventh Amendment to Third Amended and Restated Credit Agreement, dated as of December 22, 2025 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on December 22, 2025).
10.28#	Permian Resources Corporation 2023 Long Term Incentive Plan (incorporated by reference to Exhibit 10.23 to the Company's Annual Report on Form 10-K filed with the SEC on February 29, 2024).
10.29	Second Amended and Restated Registration Rights Agreement, dated January 7, 2026, by and between the Company, Old PR and the signatories thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2026).
10.30	Share Surrender and Unit Exchange Agreement, dated as of January 7, 2026, by and among Permian Resources Corporation (n/k/a Permian Resources Holdings Inc.), Permian Resources Operating, LLC, PRC NewCo Inc (n/k/a Permian Resources Corporation) and the individuals set forth on the signature pages thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2026).
10.31#*	Form of Restricted Stock Unit Agreement under the Permian Resources Corporation 2023 Long Term Incentive Plan.
19.1*	Insider Trading Policy.
21.1*	Subsidiaries of the Registrant
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Co-Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a).
31.2*	Certification of the Co-Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a).
31.3*	Certification of the Chief Financial Officer required by Rule 13a-14(a) or Rule 15d-14(a).
32.1*	Certification of the Co-Chief Executive Officers required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
32.2*	Certification of the Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
97.1*	Clawback Policy
99.1	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2023 (incorporated by reference to Exhibit 99.3 to the Company's Annual Report on Form 10-K filed with the SEC on February 29, 2024).
99.2	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2024 (incorporated by reference to Exhibit 99.3 to the Company's Annual Report on Form 10-K filed with the SEC on February 26, 2025).
99.3*	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2025.
101.INS*	Inline XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith.

Management contract or compensatory plan or agreement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

PERMIAN RESOURCES CORPORATION

By: /s/ GUY M. OLIPHINT

Guy M. Oliphint
Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Act of 1934, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ WILLIAM M. HICKEY, III William M. Hickey, III	Co-Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2026
/s/ JAMES H. WALTER James H. Walter	Co-Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2026
/s/ GUY M. OLIPHINT Guy M. Oliphint	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2026
/s/ ROBERT R. SHANNON Robert R. Shannon	Executive Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2026
/s/ STEVEN D. GRAY Steven D. Gray	Chairman	February 26, 2026
/s/ MAIRE A. BALDWIN Maire A. Baldwin	Director	February 26, 2026
/s/ FROST W. COCHRAN Frost W. Cochran	Director	February 26, 2026
/s/ KARAN E. EVES Karan E. Eves	Director	February 26, 2026
/s/ ARON MARQUEZ Aron Marquez	Director	February 26, 2026
/s/ WILLIAM J. QUINN William J. Quinn	Director	February 26, 2026
/s/ JEFFREY H. TEPPER Jeffrey H. Tepper	Director	February 26, 2026
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	February 26, 2026

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Directors

Steven Gray

Maire Baldwin

Frost Cochran

Karan Eves

Will Hickey

Aron Marquez

William Quinn

Jeffrey Tepper

Robert Tichio

James Walter

Executive Officers

Will Hickey
Co-Chief Executive Officer

James Walter
Co-Chief Executive Officer

Guy Oliphint
EVP and Chief Financial Officer

John Bell
EVP and General Counsel

Brandon Gaynor
EVP of Business Development and Strategy

Casey McCain
EVP of Production Operations

Robert Shannon
EVP and Chief Accounting Officer

Clayton Smith
EVP of Development Operations

Company Information

Corporate Headquarters
300 N. Marienfeld Street
Suite 1000
Midland, Texas 79701

432-695-4222
info@permianres.com

Annual Meeting
The Annual Meeting will be held at the Petroleum Club of Midland on May 19, 2026

Independent Registered Public Accounting Firm
KPMG LLP

Registrar and Stock Transfer Agent
Continental Stock Transfer & Trust Company

Stock Exchange
Common Stock traded on the New York Stock Exchange under the symbol PR

Investor Relations
Hays Mabry

832-240-3265
ir@permianres.com

300 N. Marienfeld Street, Suite 1000, Midland, Texas 79701

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