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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

or

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

For the transition period from to

Commission File Number 001-35410

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas	**27-4662601**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
5400 LBJ Freeway, Suite 1500	
Dallas, Texas	**75240**
(Address of principal executive offices)	**(Zip Code)**

(972) 371-5200
(Registrant's telephone number, including area code)

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

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01 per share	MTDR	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 such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

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

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

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

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

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). ☐

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was $5,506,467,014.

As of February 24, 2026, there were 124,249,941 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2026 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Auditor Name: KPMG LLP Auditor Location: Dallas, TX Auditor Firm ID: 185

MATADOR RESOURCES COMPANY

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2025

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K (this "Annual Report") constitute "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"). Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. All statements, other than statements of historical fact, included in this Annual Report regarding our strategy, future operations, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecasted," "hypothetical," "intend," "may," "might," "plan," "potential," "predict," "project," "seek," "should," "would" or other similar words, although not all forward-looking statements contain such identifying words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include those described in "Item 1A. Risk Factors" in this Annual Report, as well as the following factors, among others: general economic conditions, including the effects of inflation and interest rates; tariffs and trade tensions; our ability to execute our business plan, including whether our drilling program is successful; changes in oil, natural gas and natural gas liquids ("NGL") prices and the demand for oil, natural gas and NGLs; our ability to replace reserves and efficiently develop current reserves; the operating results of our midstream business's oil, natural gas and water gathering and transportation systems, pipelines and facilities, the acquiring of third-party business and the drilling of any additional salt water disposal wells; costs of operations; delays and other difficulties related to producing oil, natural gas and NGLs or the construction, expansion or operation of our midstream assets; delays and other difficulties related to regulatory and governmental approvals and restrictions; impact on our operations due to seismic events; availability of sufficient capital to execute our business plan, including from future cash flows, capital markets, available borrowing capacity under our revolving credit facilities and otherwise; our ability to make acquisitions on economically acceptable terms; our ability to integrate acquisitions; the operating results of, and availability of any potential distributions from, our joint ventures; weather conditions, environmental conditions and natural disasters; disruption from our acquisitions making it more difficult to maintain business and operational relationships; significant transaction costs associated with our acquisitions; the risk of litigation and/or regulatory actions related to our acquisitions; evolving cybersecurity risks; and the other factors discussed below and elsewhere in this Annual Report and in other documents that we file with or furnish to the United States Securities and Exchange Commission (the "SEC"), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our estimated future reserves and the present value thereof, including whether or not a full-cost ceiling impairment could be realized;
- our cash flows and liquidity;
- the amount, timing and payment of dividends, if any;
- our financial strategy, budget, projections and operating results;
- the supply and demand of oil, natural gas and NGLs;
- oil, natural gas and NGL prices, including our realized prices thereof;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil storage capacity;
- the availability and cost of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- the integration of acquisitions with our business;
- government regulation and taxation of the oil and natural gas industry;
- tariffs and trade restrictions;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the ability of our midstream business to construct, maintain and operate midstream pipelines and facilities, including the operation of cryogenic natural gas processing plants and the drilling of additional salt water disposal wells;
- the ability of our midstream business to attract third-party volumes;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;

- competition in the oil and natural gas industry, including in both the exploration and production and midstream segments;
- the effectiveness of our risk management and hedging activities;
- our technology;
- environmental liabilities;
- our initiatives and efforts relating to environmental, social and governance matters;
- counterparty credit risk;
- geopolitical instability and developments in oil-producing and natural gas-producing countries;
- our future operating results;
- the impact of the Inflation Reduction Act of 2022 (the "IRA");
- the impact of the One Big Beautiful Bill Act of 2025 (the "OBBBA"); and
- our plans, objectives, expectations and intentions contained in this Annual Report or in our other filings with the SEC that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements in this Annual Report are reasonable based on information available to us on the date hereof, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

PART I

Item 1. Business.

In this Annual Report, (i) references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise), (ii) references to "Matador" refer solely to Matador Resources Company, (iii) references to the "Ameredev Acquisition" refer to the acquisition of Ameredev Stateline II, LLC from affiliates of EnCap Investments L.P., including (a) certain oil and natural gas producing properties and undeveloped acreage located in Lea County, New Mexico and Loving and Winkler Counties, Texas, and (b) an approximate 19% stake in the parent company of Piñon Midstream, LLC, which was completed by a subsidiary of the Company on September 18, 2024, (iv) references to the "Advance Acquisition" refer to the acquisition of Advance Energy Partners Holdings, LLC from affiliates of EnCap Investments L.P., including certain oil and natural gas producing properties, undeveloped acreage and midstream assets located primarily in Lea County, New Mexico and Ward County, Texas, that was completed by a subsidiary of the Company on April 12, 2023, and the acquisition of additional interests from affiliates of EnCap Investments L.P., including overriding royalty interests and royalty interests in certain oil and natural gas properties located primarily in Lea County, New Mexico on December 1, 2023, (v) references to "San Mateo" refer to San Mateo Midstream, LLC, collectively with its subsidiaries (including, as of December 18, 2024, Pronto), and (vi) references to "Pronto" refer to Pronto Midstream, LLC, together with its subsidiary. For certain oil and natural gas terms used in this Annual Report, see the "Glossary of Oil and Natural Gas Terms" included in this Annual Report.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also have operations in the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, we conduct midstream operations in support of, and to provide flow assurance for, our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and produced water gathering services and produced water disposal services to third parties.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman and Chief Executive Officer. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum

Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown Inc., in an all-cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the New York Stock Exchange (the "NYSE") under the symbol "MTDR." Prior to trading on the NYSE, there was no established public trading market for our common stock.

Our goal is to increase shareholder value by building oil and natural gas reserves, production and cash flows and providing midstream services at an attractive rate of return on invested capital. We plan to achieve our goal by, among other items, executing the following business strategies:

- focus our exploration and development activities primarily on unconventional plays, including the Wolfcamp and Bone Spring plays in the Delaware Basin;
- identify, evaluate and develop additional oil and natural gas plays as necessary to maintain a balanced portfolio of oil and natural gas properties;
- continue to improve operational and cost efficiencies;
- identify and develop midstream opportunities that support and enhance our exploration and development activities and that generate value for San Mateo and Matador;
- maintain our financial discipline;
- return capital to shareholders;
- pursue opportunistic acquisitions, divestitures and joint ventures; and
- provide the energy that society needs in a manner that is safe, protects the environment and is consistent with the oil and natural gas industry's best practices.

The successful execution of our business strategies led to increases in our oil and natural gas production and proved oil and natural gas reserves in 2025. We improved the capital efficiency of our drilling and completion operations and achieved several key operational milestones throughout the year (as further described below in "—Exploration and Production Segment—Southeast New Mexico and West Texas—Delaware Basin"). We also secured firm transportation on Energy Transfer's Hugh Brinson Pipeline, which is expected to come online in the fourth quarter of 2026, to move 500,000 MMBtu per day of natural gas production out of the Permian Basin to East Texas and markets along the Gulf Coast where demand and pricing have historically been significantly higher than at the Waha Hub.

In addition, we achieved several key capital resources objectives during the year, including generating free cash flow, paying down a portion of the borrowings that funded the Ameredev Acquisition, increasing our quarterly cash dividend and earning performance incentives from Five Point Infrastructure, LLC or its affiliates (previously, Five Point Energy LLC) ("Five Point"), our joint venture partner in San Mateo.

San Mateo also achieved important milestones in 2025, including the construction of an additional natural gas processing plant with a designed inlet capacity of 200 MMcf per day, including a nitrogen rejection unit and additional related facilities, to expand its Marlan cryogenic natural gas processing plant (the "Marlan Processing Plant"). The Marlan Processing Plant expansion came online in the second quarter of 2025 and increased San Mateo's total natural gas cryogenic processing capacity 38% to 720 MMcf per day.

2025 Highlights

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2025, we achieved record oil, natural gas and average daily oil equivalent production. In 2025, we produced 43.7 million Bbl of oil, an increase of 20%, as compared to 36.5 million Bbl of oil produced in 2024. We also produced 191.3 Bcf of natural gas, an increase of 23% from 155.8 Bcf of natural gas produced in 2024. Our average daily oil equivalent production for the year ended December 31, 2025 was 207,070 BOE per day, including 119,723 Bbl of oil per day and 524.1 MMcf of natural gas per day, an increase of 21%, as compared to 170,751 BOE per day, including 99,808 Bbl of oil per day and 425.7 MMcf of natural gas per day, for the year ended December 31, 2024. The increase in oil and natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin throughout 2025, which offset our declining production in the Eagle Ford shale in South Texas that was divested in the first quarter of 2025. Oil production comprised 58% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for each of the years ended December 31, 2025 and 2024.

Increased Oil, Natural Gas and Oil Equivalent Reserves

At December 31, 2025, our estimated total proved oil and natural gas reserves were 667.0 million BOE, including 376.0 million Bbl of oil and 1.75 Tcf of natural gas, an increase of 9% from 611.5 million BOE, including 361.8 million Bbl of oil and 1.50 Tcf of natural gas, at December 31, 2024. The Standardized Measure of our total proved oil and natural gas reserves decreased 5% from $7.38 billion at December 31, 2024 to $6.99 billion at December 31, 2025. The PV-10 of our total proved oil and natural gas reserves decreased 11% from $9.23 billion at December 31, 2024 to $8.24 billion at December 31, 2025. The decreases in our Standardized Measure and PV-10 were primarily a result of the lower unweighted arithmetic average oil and natural gas prices used to estimate proved reserves at December 31, 2025, as compared to December 31, 2024, partially offset by a 9% increase in our total proved oil and natural gas reserves at December 31, 2025, as compared to December 31, 2024. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "—Estimated Proved Reserves."

At December 31, 2025, estimated proved developed reserves included 223.0 million Bbl of oil and 1.11 Tcf of natural gas, and estimated proved undeveloped reserves included 153.0 million Bbl of oil and 636.6 Bcf of natural gas. Proved developed reserves and proved oil reserves comprised 61% and 56%, respectively, of our total proved oil and natural gas reserves at December 31, 2025. Proved developed reserves and proved oil reserves comprised 60% and 59%, respectively, of our total proved oil and natural gas reserves at December 31, 2024.

Operational Highlights

We focus on optimizing the development of our resource base by seeking ways to maximize our recovery per well relative to the cost incurred and to minimize our operating costs per BOE produced. We apply an analytical approach to track and monitor the effectiveness of our drilling and completion techniques and service providers. This allows us to better manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation. Additionally, we concentrate on our core areas, which allows us to achieve economies of scale and reduce operating costs. Largely as a result of these factors, we believe that we have increased our technical knowledge of drilling, completing and producing Delaware Basin wells. We expect the Delaware Basin will continue to be our primary area of focus in 2026.

We completed and began producing oil and natural gas from 258 gross (129.3 net) horizontal wells in the Delaware Basin in 2025, including 151 gross (121.2 net) operated and 107 gross (8.1 net) non-operated wells. At December 31, 2025, our total acreage position in the Delaware Basin was approximately 354,600 gross (212,500 net) acres, primarily in Lea and Eddy Counties, New Mexico and Loving, Ward and Winkler Counties, Texas. We have focused our Delaware Basin operations on the following asset areas: the Stateline, Rustler Breaks and Arrowhead asset areas in Eddy County, New Mexico, the Antelope Ridge, Ranger and Twin Lakes asset areas in Lea County, New Mexico and the West Texas asset area in Loving, Ward and Winkler Counties, Texas. Our Delaware Basin properties are the most significant component of our asset portfolio. We expect our Delaware Basin production to increase in 2026 as we continue the delineation and development of these asset areas.

During 2025, we achieved several operational highlights in the Delaware Basin. These highlights (as further described below in "—Exploration and Production Segment—Southeast New Mexico and West Texas—Delaware Basin") included:

- improved well performance and cost efficiencies through large-scale batch developments. For example, during the second half of 2025, we turned to sales a 17-well batch development, one of the largest developments in our history, on our John Callahan unit in the Antelope Ridge asset area in Lea County, New Mexico targeting multiple horizons in the Bone Springs and Wolfcamp formations;
- reduced drilling and completion costs per lateral foot, including increased efficiencies and capital savings through the continued use of Simul-Frac and Trimul-Frac;
- continued drilling of longer laterals, with average completed lateral length for operated wells turned to sales in 2025 of approximately 10,400 feet; and
- capital expenditures for drilling, completing and equipping wells ("D/C/E capital expenditures") for 2025 of $1.53 billion, which was within our estimated range for 2025 D/C/E capital expenditures of $1.47 to $1.55 billion, as provided on October 21, 2025.

Capital Resources and Financing Highlights

During 2025, we achieved several significant and important capital resources objectives, which included:

- the generation of free cash flow in all four quarters of 2025;
- the amendment of our dividend policy two times during 2025, pursuant to which we increased the quarterly cash dividend from $0.25 per share of common stock in the fourth quarter of 2024 to $0.375 per share of common stock;

- the receipt of $136.7 million in cash distributions from San Mateo and $13.0 million in performance incentives directly from Five Point;
- the implementation in April 2025 of a share repurchase program (the "Share Repurchase Program") authorizing the repurchase of up to $400.0 million of common stock, and the purchase of 1,351,328 shares of common stock under the Share Repurchase Program in 2025 at a weighted average price of $41.31 per common share for a total cost of $55.8 million;
- the amendment of San Mateo's secured revolving credit facility (the "San Mateo Credit Facility") in December 2025 to increase the lender commitments from $850.0 million to $1.10 billion, and to amend the accordion feature to provide for potential increases in lender commitments of up to $1.35 billion; and
- an upgrade to our long-term issuer default rating by Fitch Ratings from 'BB-' to 'BB'.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" for additional information.

Midstream Highlights

Matador conducts its midstream operations primarily through San Mateo, which is owned 51% by us and 49% by our joint venture partner, Five Point.

San Mateo achieved strong operating results in 2025, highlighted by (i) free cash flow generation, (ii) expansion of the Marlan Processing Plant (iii) increased midstream services revenues, including those from third-party customers, and (iv) increased natural gas gathering and processing volumes.

At December 31, 2025, San Mateo's midstream system included:

- Natural Gas Assets: 720 MMcf per day of designed natural gas cryogenic processing capacity and approximately 340 miles of natural gas gathering pipelines in Eddy and Lea Counties, New Mexico and Loving County, Texas, including 43 miles of large diameter natural gas gathering lines spanning from the Stateline asset area to the southern portion of the Arrowhead asset area (the "Greater Stebbins Area");
- Oil Assets: three oil central delivery points ("CDP") with over 100,000 Bbl of designed oil throughput capacity and approximately 120 miles of oil gathering and transportation pipelines in Eddy County, New Mexico and Loving County, Texas, as well as a 400,000-acre joint development area with Plains Marketing, L.P. ("Plains") to gather our and other producers' oil production in Eddy County, New Mexico; and
- Produced Water Assets: 16 commercial salt water disposal wells and associated facilities with designed produced water disposal capacity of 475,000 Bbl per day and approximately 195 miles of produced water gathering pipelines in Eddy County, New Mexico and Loving County, Texas.

Sustainability Practices

We are committed to creating value for our shareholders in a responsible manner. Our aim is to reliably and profitably provide the oil and gas that society needs in a manner that is safe, protects the environment and is consistent with the industry's best practices and the highest applicable regulatory and legal standards. We also communicate our stewardship efforts in our annual Sustainability Report using quantitative metrics aligned with standards developed by the Sustainability Accounting Standards Board (SASB).

Highlights from our sustainability efforts are noted below. The data utilized in calculating the below metrics is subject to certain reporting rules, regulatory reviews, definitions, calculation methodologies, estimates, adjustments and other factors. The emissions-related metrics for 2025 were not readily available prior to the filing of this Annual Report and, therefore, are presented as related to our 2024 operations. As of the date of this Annual Report, we are not aware of any material changes to the emissions-related metrics subsequent to the publishing of the 2024 Sustainability Report, assuming the calculation methodology remains consistent for the 2025 reporting year. All other metrics are presented as related to our 2025 operations. The metrics reflect both Matador's gross operated exploration and production operations and gross operated midstream operations (which includes San Mateo) on a consolidated basis, except where otherwise noted or immaterial in scope.

- decreased Matador's direct greenhouse gas emissions intensity by 65% in 2024, as compared to 2019;
- decreased Matador's methane emissions intensity by 88% in 2024, as compared to 2019;
- decreased Matador's flaring intensity by 84% in 2024, as compared to 2019;
- utilized non-fresh water in 98% of total water consumption in 2025;

- utilized recycled produced water for 72% of total water consumption in hydraulic fracturing operations in 2025;
- transported 99% of operated produced water and 97% of operated produced oil by pipeline in 2025; and
- provided approximately 26,800 hours of employee continuing education, equating to approximately 56 hours per employee in 2025.

Exploration and Production Segment

Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also have operations in the Haynesville shale and Cotton Valley plays in Northwest Louisiana. During 2025, we devoted most of our efforts and most of our capital expenditures to our drilling and completion operations and midstream operations in the Wolfcamp and Bone Spring plays in the Delaware Basin. Since our inception, our exploration and development efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2025.

			Producing Wells		Total Identified Drilling Locations[1]		Estimated Net Proved Reserves[2]		
	Gross Acreage	Net Acreage	Gross	Net	Gross	Net	MBOE[3]	% Developed	Avg. Daily Production (BOE/d)[3]
Southeast New Mexico/West Texas:									
Delaware Basin[4]	354,600	212,500	2,179	1,137.1	5,295	1,802	662,248	60.9	203,330
South Texas:									
Eagle Ford[5]	—	—	—	—	—	—	—	—	105
Northwest Louisiana									
Haynesville	16,200	8,900	279	18.5	129	13	4,302	100.0	3,534
Cotton Valley[6]	15,800	14,800	64	38.7	144	37	497	100.0	101
Area Total[7]	18,500	17,300	343	57.2	273	50	4,799	100.0	3,635
Total	373,100	229,800	2,522	1,194.3	5,568	1,852	667,047	61.2	207,070

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2025. The total net engineered drilling locations are calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. Individual horizontal drilling locations generally represent a variety of lateral lengths, from one mile to greater than two miles, based upon our current assumptions for a well that could be drilled at that location given our current acreage position. At December 31, 2025, approximately 76% of these identified drilling locations in the Delaware Basin were expected to be horizontal laterals with lateral lengths of approximately two miles or greater, and approximately 91% are expected to have lateral lengths of approximately 1.5 miles or greater. At December 31, 2025, these engineered drilling locations included 522 gross (255 net) operated and non-operated locations to which we have assigned proved undeveloped reserves, primarily in the Wolfcamp or Bone Spring plays, but also in the Brushy Canyon and Avalon formations, in the Delaware Basin. At December 31, 2025, we had assigned no proved undeveloped reserves to our leasehold in Northwest Louisiana.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. For additional information regarding our oil and natural gas reserves, see "—Estimated Proved Reserves" and Supplemental Oil and Natural Gas Disclosures included in the unaudited supplementary information in this Annual Report, which is incorporated herein by reference.

(3) Production volumes and proved reserves reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring, Brushy Canyon, Yeso and Avalon plays on our acreage in the Delaware Basin at December 31, 2025.

(5) During the first quarter of 2025, the Company sold its remaining South Texas assets in the Eagle Ford shale.

(6) Includes the Cotton Valley formation and shallower zones.

(7) Some of the same leases cover the net acres shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

We are active both as an operator and as a non-operating, co-working interest owner with various industry participants. At December 31, 2025, we operated a significant majority of our acreage in the Delaware Basin in Southeast New Mexico and West Texas. In those wells where we are not the operator, our working interests are often relatively small. At December 31, 2025, we also operated approximately 51% of our Northwest Louisiana acreage.

While we do not always have direct access to our operating partners' drilling plans with respect to future well locations on non-operated properties, we do attempt to maintain ongoing communications with the technical staff of these operators in an

effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

Southeast New Mexico and West Texas — Delaware Basin

The greater Permian Basin in Southeast New Mexico and West Texas is a mature exploration and production region with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in this basin had focused on relatively conventional reservoir targets, but the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology has enhanced the development potential of this basin, particularly in the organic rich shales, or source rocks, of the Wolfcamp formation and in the low permeability sand and carbonate reservoirs of the Bone Spring, Brushy Canyon and Avalon formations.

In the western part of the Permian Basin, also known as the Delaware Basin, there are multiple horizontal targets in a given area that exist within the several thousand feet of hydrocarbon bearing layers that make up the Bone Spring and Wolfcamp plays. Multiple horizontal drilling and completion targets are being identified and targeted by companies, including us, throughout the vertical section, including the Brushy Canyon, Avalon and Bone Spring (First, Second and Third Sand and Carbonate) and several intervals within the Wolfcamp shale, often identified as Wolfcamp A through D.

At December 31, 2025, our total acreage position in Southeast New Mexico and West Texas was approximately 354,600 gross (212,500 net) acres, primarily in Lea and Eddy Counties, New Mexico and Loving, Ward and Winkler Counties, Texas. These acreage totals included approximately 75,200 gross (42,800 net) acres in our Ranger asset area in Lea County, 61,400 gross (26,300 net) acres in our Arrowhead asset area in Eddy County, 47,000 gross (26,600 net) acres in our Rustler Breaks asset area in Eddy County, 77,000 gross (59,000 net) acres in our Antelope Ridge asset area in Lea County, 2,900 gross (2,900 net) acres in our Stateline asset area in Eddy County, 57,000 gross (32,100 net) acres in our Twin Lakes asset area in Lea County and 33,500 gross (22,300 net) acres in our West Texas asset area in Loving, Ward and Winkler Counties at December 31, 2025. We consider the vast majority of our Delaware Basin acreage position to be prospective for oil and liquids-rich targets in the Bone Spring and Wolfcamp formations. Other potential targets on certain portions of our acreage include the Brushy Canyon and Avalon formations, as well as the Abo, Strawn, Devonian, Penn Shale, Atoka, Yeso and Morrow formations. At December 31, 2025, our acreage position in the Delaware Basin was approximately 81% held by existing production. Excluding the Twin Lakes asset area, our acreage position in the Delaware Basin was approximately 90% held by existing production at December 31, 2025.

During the year ended December 31, 2025, we continued the delineation and development of our Delaware Basin acreage. We completed and began producing oil and natural gas from 258 gross (129.3 net) horizontal wells in the Delaware Basin, including 151 gross (121.2 net) operated horizontal wells and 107 gross (8.1 net) non-operated horizontal wells, throughout our various asset areas. At December 31, 2025, we had tested a number of different producing horizons at various locations across our acreage position, including the Brushy Canyon, two benches of the Avalon, two benches of the First Bone Spring, the Second Bone Spring Carbonate, three benches of the Second Bone Spring Sand, three benches of the Third Bone Spring Carbonate, two benches of the Third Bone Spring Sand, four benches of the Wolfcamp A, including the X, Y and Z sands and the more organic, lower section of the Wolfcamp A, three benches of the Wolfcamp B, the Wolfcamp D, the Strawn and the Morrow.

At December 31, 2025, approximately 99% of our estimated total proved oil and natural gas reserves, or 662.2 million BOE, was attributable to the Delaware Basin, including approximately 376.0 million Bbl of oil and 1.72 Tcf of natural gas, a 9% increase, as compared to 606.2 million BOE for the year ended December 31, 2024. Our Delaware Basin proved reserves at December 31, 2025 and 2024 comprised approximately 100% of our proved oil reserves and 98% of our proved natural gas reserves.

At December 31, 2025, we had identified 5,295 gross (1,802 net) engineered locations for potential future drilling on our Delaware Basin acreage, primarily in the Wolfcamp and Bone Spring plays, but also including the shallower Brushy Canyon, Yeso and Avalon formations. At December 31, 2025, these locations had a total net lateral length of approximately 19.1 million feet, or 3,801 miles, an increase of 4% as compared to the total net lateral length of approximately 18.3 million feet, or 3,680 miles, as of December 31, 2024. These locations include 2,492 gross (1,599 net) locations that we anticipate operating as we hold a working interest of at least 25% in each of these locations. Individual horizontal drilling locations represent a variety of lateral lengths, from one mile to greater than two miles based upon our current assumptions for a well that could be drilled at specified locations given our current acreage position. At December 31, 2025, approximately 76% of these identified drilling locations are expected to have horizontal lateral lengths of approximately two miles or greater and approximately 91% are expected to have horizontal lateral lengths of approximately 1.5 miles or greater. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our Delaware Basin wells and other nearby wells based on

available public data, drilling densities anticipated on our properties and properties of other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Our engineered well locations, at December 31, 2025, do not yet include all portions of our acreage position. Our identified well locations presume that multiple intervals may be prospective at any one surface location. Although we believe that denser well spacing may be possible in certain asset areas or in certain formations, at December 31, 2025, the majority of our estimated locations were based on the assumption of 160-acre well spacing. As we explore and develop our Delaware Basin acreage further, we anticipate that we may identify additional locations for future drilling. At December 31, 2025, these potential future drilling locations included 522 gross (255 net) operated and non-operated locations in the Delaware Basin, primarily in the Wolfcamp and Bone Spring plays, but also in the Brushy Canyon and Avalon, to which we have assigned proved undeveloped reserves.

Antelope Ridge Asset Area - Lea County, New Mexico

In the Antelope Ridge asset area, we turned to sales 84 gross (73.2 net) operated wells and 27 gross (0.5 net) non-operated wells during 2025.

In the second half of 2025, we turned to sales 17 gross (13.7 net) operated wells on our John Callahan unit in the Antelope Ridge asset area in Lea County, which is one of the largest developments in our history. These wells, which included four First Bone Spring, three Third Bone Spring, one Third Bone Spring Carbonate, three Wolfcamp A-XY, three Wolfcamp A and three Wolfcamp B completions, have produced in aggregate approximately 2.1 million BOE in approximately four months of production. These 17 wells had average completed lateral lengths of approximately 10,300 feet.

We turned to sales an additional 67 gross (59.5 net) operated Antelope Ridge wells. These 67 wells, which included six First Bone Spring, six Second Bone Spring, 12 Third Bone Spring, eight Third Bone Spring Carbonate, 20 Wolfcamp A-XY, eight Wolfcamp A and seven Wolfcamp B completions, have produced in aggregate approximately 9.0 million BOE in an average of approximately seven months of production. These 67 wells had average completed lateral lengths of approximately 10,600 feet.

Ranger and Twin Lakes Asset Areas - Lea County, New Mexico

In the Ranger asset area, we turned to sales nine gross (7.5 net) operated wells and 22 gross (2.8 net) non-operated wells during 2025.

In total, these nine Ranger operated wells, which included five Second Bone Spring and four Wolfcamp D completions, have produced in aggregate approximately 0.7 million BOE in an average of approximately five months of production. These nine wells had average completed lateral lengths of approximately 10,600 feet.

In the Twin Lakes asset area, we turned to sales one gross (0.5 net) operated well, and we did not turn to sales or participate in any non-operated wells during 2025.

Arrowhead Asset Area - Eddy County, New Mexico

We turned to sales 22 gross (12.0 net) operated wells in the Arrowhead asset area during 2025. These wells, which included 14 Second Bone Spring and eight Wolfcamp A-XY completions, have produced in aggregate approximately 5.5 million BOE in approximately seven months of production. These 22 wells had average completed lateral lengths of approximately 10,000 feet.

We also turned to sales 21 gross (2.4 net) non-operated wells in the Arrowhead asset area during 2025.

Rustler Breaks Asset Area - Eddy County, New Mexico

We turned to sales 26 gross (19.3 net) operated wells in the Rustler Breaks asset area during 2025. In total, these 26 Rustler Breaks wells, which included seven First Bone Spring, five Second Bone Spring, four Third Bone Spring, six Third Bone Spring Carbonate, three Wolfcamp A-XY and one Wolfcamp B completions, have produced in aggregate approximately 4.3 million BOE in an average of approximately six months of production. These 26 wells had average completed lateral lengths of approximately 10,100 feet.

We also turned to sales 36 gross (2.2 net) non-operated wells in the Rustler Breaks asset area during 2025.

Stateline Asset Area - Eddy County, New Mexico

We did not conduct any operated or non-operated drilling and completion activities on our leasehold properties in the Stateline asset area during 2025.

West Texas Asset Area - Loving, Ward and Winkler Counties, Texas

We turned to sales nine gross (8.7 net) operated wells in the West Texas asset area during 2025. In total, these nine West Texas wells, which included two Third Bone Spring, one Wolfcamp A and six Wolfcamp B completions, have produced in aggregate approximately 0.4 million BOE in approximately three months of production. These nine wells had average completed lateral lengths of approximately 10,100 feet.

We also turned to sales one gross (0.2 net) non-operated well in the West Texas asset area during 2025.

South Texas — Eagle Ford Shale and Other Formations

During the first quarter of 2025, the Company sold its remaining South Texas assets in the Eagle Ford shale for $22.2 million.

Northwest Louisiana — Haynesville Shale, Cotton Valley and Other Formations

We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana during 2025, although we did participate in the drilling and completion of 12 gross (0.1 net) non-operated Haynesville shale wells that were turned to sales in 2025.

At December 31, 2025, we held approximately 18,500 gross (17,300 net) acres in Northwest Louisiana, including 16,200 gross (8,900 net) acres in the Haynesville shale play and 15,800 gross (14,800 net) acres in the Cotton Valley play. We operate substantially all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. We operate approximately 8% of the 11,600 gross (4,700 net) acres that we consider to be in the core area of the Haynesville shale play. All of our leasehold in the Haynesville and Cotton Valley plays in Northwest Louisiana was held by existing production at December 31, 2025.

For the year ended December 31, 2025, approximately 2% of our average daily oil equivalent production, or 3,635 BOE per day, including one Bbl of oil per day and 21.8 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana, while for the year ended December 31, 2024, approximately 2% of our average daily oil equivalent production, or 3,492 BOE per day, including three Bbl of oil per day and 21.0 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana. For the year ended December 31, 2025, approximately 4% of our daily natural gas production, or 21.8 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana, while for the year ended December 31, 2024, approximately 5% of our daily natural gas production, or 21.0 MMcf of natural gas per day, was attributable to these properties. At December 31, 2025, less than 1% of our estimated total proved reserves, or 4.8 million BOE, was attributable to our properties in Northwest Louisiana.

Midstream Segment

Our midstream segment conducts midstream operations in support of, and provides flow assurance for, our exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and produced water gathering services and produced water disposal services to third parties.

Southeast New Mexico and West Texas — Delaware Basin

On February 17, 2017, we announced the formation of San Mateo, a strategic joint venture with Five Point. The midstream assets that were contributed to San Mateo included (i) San Mateo's Black River cryogenic natural gas processing plant in Eddy County, New Mexico (the "Black River Processing Plant") (before its expansions); (ii) one salt water disposal well and a related commercial salt water disposal facility in the Rustler Breaks asset area; (iii) three salt water disposal wells and related commercial salt water disposal facilities in the West Texas asset area; and (iv) substantially all related oil, natural gas and produced water gathering systems and pipelines in both the Rustler Breaks asset area and in Loving County, Texas (collectively, the "Delaware Midstream Assets"). We received $171.5 million in connection with the formation of San Mateo and earned all of the potential $73.5 million in performance incentives through January 31, 2023. In connection with the formation of San Mateo, we dedicated to San Mateo current and certain future leasehold interests in the Rustler Breaks asset area and the Wolf portion of the West Texas asset area pursuant to 15-year, fixed fee oil, natural gas and produced water gathering and produced water disposal agreements. In addition, we dedicated current and certain future leasehold interests in the Rustler Breaks asset area to San Mateo pursuant to a 15-year, fixed fee natural gas processing agreement.

On February 25, 2019, we announced the formation of San Mateo Midstream II, LLC ("San Mateo II"), a strategic joint venture with Five Point designed to expand our midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. In addition, Five Point committed to pay $125.0 million of the first $150.0 million of capital expenditures incurred by San Mateo II to develop facilities in the Greater Stebbins Area and the Stateline asset area. The $150.0 million threshold for capital expenditures was reached during 2020 and additional capital expenditures are the responsibility of the Company and Five Point based on each company's proportionate interest in San Mateo. In addition, we earned $108.2 million in performance

incentives through September 30, 2024. In connection with the formation of San Mateo II, we dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee oil transportation, oil, natural gas and produced water gathering, natural gas processing and produced water disposal agreements.

Effective October 1, 2020, San Mateo II merged with and into San Mateo. The Company and Five Point own 51% and 49% of San Mateo, respectively. San Mateo provides firm service to us, while also being a midstream service provider to other customers in and around our Stateline, West Texas and Rustler Breaks asset areas and the Greater Stebbins Area. We retain operational control of San Mateo and continue to operate the Delaware Midstream Assets, the expanded Black River Processing Plant and the other midstream facilities that have been developed in the Greater Stebbins Area and the Stateline asset area.

On June 30, 2022, we acquired Pronto, including the Marlan Processing Plant (prior to expansion), three compressor stations and approximately 45 miles of natural gas gathering pipelines in Lea and Eddy Counties, New Mexico.

On April 13, 2023, we completed the Advance Acquisition, which included one commercial salt water disposal well, approximately 28 miles of water gathering assets and approximately 17 miles of natural gas gathering pipelines.

On September 18, 2024, we completed the Ameredev Acquisition, which included approximately 180 miles of natural gas gathering, water gathering and oil transportation and gathering pipeline assets.

On December 18, 2024, we completed a transaction with Five Point in which we contributed Pronto, a wholly-owned subsidiary of the Company, to San Mateo, and Five Point made a cash contribution to San Mateo of $171.5 million (the "Pronto Transaction"). In connection with the Pronto Transaction, we received a special distribution from San Mateo of approximately $219.8 million. In addition, we have the potential to earn up to $75.0 million in incentive payments from Five Point over a five-year period, of which $13.0 million and $1.3 million was paid by Five Point during the years ended December 31, 2025 and 2024, respectively. San Mateo continues to be owned 51% by us and 49% by Five Point.

In connection with the Pronto Transaction, Matador dedicated to San Mateo its current and certain future leasehold interests in the Ranger and Antelope Ridge asset areas pursuant to 15-year, fixed fee natural gas gathering, compression, treating and processing agreements whereby San Mateo will gather, compress, treat and process natural gas produced from our operated wells in northern Lea County, New Mexico. In addition, San Mateo entered into certain agreements with Northwind Midstream Partners LLC ("Northwind"), previously an affiliate of Five Point, whereby Northwind will treat certain sour gas gathered and delivered by San Mateo in northern Lea County, New Mexico. Under these agreements, Northwind will redeliver the treated sweet gas from San Mateo and other third-party customers to San Mateo for processing.

Natural Gas Gathering and Processing Assets

The Black River Processing Plant and associated gathering system (the "Black River Gathering System") were originally built to support our ongoing and future development efforts in the Rustler Breaks asset area and to provide us with firm takeaway and processing services for our Rustler Breaks natural gas production. We had previously completed the installation and testing of a 12-inch natural gas trunk line and associated gathering lines running throughout the length of our Rustler Breaks acreage position, and these natural gas gathering lines are being used to gather almost all of our operated natural gas production at Rustler Breaks.

In 2020, San Mateo completed the construction and successful start-up of the expansion of the Black River Processing Plant to add an incremental designed inlet capacity of 200 MMcf of natural gas per day to the existing designed inlet capacity of 260 MMcf of natural gas per day, bringing the total designed inlet capacity to 460 MMcf of natural gas per day. The expanded Black River Processing Plant supports our exploration and development activities in the Delaware Basin and, at December 31, 2025, was also gathering and processing natural gas from the Stateline asset area and from the Greater Stebbins Area. The Black River Processing Plant also processes natural gas from our Rustler Breaks asset area and provides natural gas processing services for other San Mateo customers in the area.

In March 2024, we completed our natural gas pipeline connections between Pronto and the Black River Gathering System and between Pronto and Matador's acreage obtained in the Advance Acquisition. These connector pipelines provide further flow assurance and options for Matador and third-party customer natural gas.

Subsequent to the Pronto Transaction, San Mateo now owns and operates the expanded Marlan Processing Plant, which has a designed inlet capacity of 260 MMcf of natural gas per day, and operates Pronto's six compressor stations and approximately 150 miles of natural gas gathering pipelines in Lea and Eddy Counties, New Mexico. The expanded Marlan Processing Plant came online in the second quarter of 2025 and increased San Mateo's total natural gas cryogenic processing capacity to 720 MMcf of natural gas per day.

At December 31, 2025, San Mateo had approximately 43 miles of large diameter natural gas gathering pipelines between the Black River Processing Plant and the Stateline asset area (approximately 24 miles) and the Greater Stebbins Area (approximately 19 miles). At December 31, 2025, San Mateo was gathering or transporting almost all our operated natural gas

production via pipeline in the Stateline asset area, the Greater Stebbins Area, the Rustler Breaks asset area and the Wolf portion of our West Texas asset area.

In addition, at December 31, 2025, San Mateo had NGL pipeline connections at the Black River Processing Plant to the NGL pipelines owned by EPIC Y-Grade Pipeline LP and Enterprise Products Partners L.P. These NGL connections provide several significant benefits to us and other San Mateo customers compared to transporting NGLs by truck. San Mateo's customers receive (i) firm NGL takeaway out of the Delaware Basin, (ii) increased NGL recoveries, (iii) improved pricing realizations through lower transportation and fractionation costs, (iv) increased optionality through San Mateo's ability to operate the Black River Processing Plant in ethane recovery mode, if desired, and (v) a reliable alternative to pipe rather than to truck NGLs during severe weather events and otherwise.

In the Wolf portion of the West Texas asset area in Loving County, Texas, San Mateo gathers our natural gas production with the natural gas gathering system we retained following the sale of our wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the West Texas asset area, including a cryogenic natural gas processing plant and approximately six miles of high-pressure gathering pipelines.

At December 31, 2025, San Mateo's natural gas gathering systems included natural gas gathering pipelines and related compression and treating systems. During the year ended December 31, 2025, San Mateo gathered an average of approximately 517 MMcf of natural gas per day, an increase of 21% as compared to 426 MMcf of natural gas per day gathered during the year ended December 31, 2024. In addition, during the year ended December 31, 2025, San Mateo processed approximately 502 MMcf of natural gas per day at the Black River Processing Plant, an increase of 25%, as compared to 403 MMcf of natural gas per day processed during the year ended December 31, 2024.

Crude Oil Gathering and Transportation Assets

San Mateo and Plains have entered into a strategic relationship to gather and transport crude oil for upstream producers in Eddy County, New Mexico and have agreed to work together through a joint tariff arrangement and related transactions to offer producers located within a joint development area crude oil transportation services from the wellhead to Midland, Texas with access to other end markets.

At December 31, 2025, San Mateo had (i) a crude oil gathering and transportation system in the Greater Stebbins Area that was connected to the existing interconnect in the Rustler Breaks asset area totaling approximately 80 miles of various diameter crude oil pipelines and (ii) a crude oil gathering system in the Stateline asset area. With these oil gathering and transportation systems (collectively with the crude oil gathering and transportation system in the Rustler Breaks asset area and the crude oil gathering system in the West Texas asset area, the "San Mateo Oil Pipeline Systems") in service, at December 31, 2025, we estimated almost all of our oil production from the Stateline, West Texas and Rustler Breaks asset areas and the Greater Stebbins Area was transported by pipeline.

At December 31, 2025, the San Mateo Oil Pipeline Systems included crude oil gathering and transportation pipelines from points of origin in Eddy County, New Mexico and Loving County, Texas to interconnects with Plains and two trucking facilities. During the year ended December 31, 2025, the San Mateo Oil Pipeline Systems had throughput of approximately 52,900 Bbl of oil per day, an increase of 1%, as compared to throughput of approximately 52,600 Bbl of oil per day during the year ended December 31, 2024.

Produced Water Gathering and Disposal Assets

At December 31, 2025, San Mateo had four commercial salt water disposal wells and associated facilities in the Greater Stebbins Area, nine commercial salt water disposal wells and associated facilities in the Rustler Breaks asset area, three commercial salt water disposal wells and associated facilities in the West Texas asset area and produced water gathering systems in the Stateline, Rustler Breaks and West Texas asset areas and the Greater Stebbins Area. At December 31, 2025, San Mateo had designed disposal capacity of approximately 475,000 Bbl of produced water per day. In addition, at December 31, 2025, Matador had three commercial salt water disposal wells and associated facilities with a designed inlet capacity of 87,500 Bbl of produced water per day.

During the year ended December 31, 2025, San Mateo handled approximately 418,000 Bbl of produced water per day, a decrease of 10%, as compared to approximately 462,400 Bbl of produced water per day handled during the year ended December 31, 2024, primarily due to lower volumes from Matador and third-party customers.

Northwest Louisiana

In Northwest Louisiana, we have midstream assets that gather natural gas from most of our operated leases. Our midstream assets in Northwest Louisiana are not part of San Mateo as of December 31, 2025.

Operating Summary

The following table sets forth certain unaudited production and operating data for the years ended December 31, 2025, 2024 and 2023.

	Year Ended December 31,		
	2025	2024	2023
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	43,699	36,530	27,542
Natural gas (Bcf)	191.3	155.8	123.4
Total oil equivalent (MBOE)[1]	75,581	62,495	48,112
Average daily production (BOE/d)[1]	207,070	170,751	131,813
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 64.99	$ 75.89	$ 77.88
Oil, with realized derivatives (per Bbl)	$ 64.99	$ 75.89	$ 77.88
Natural gas, without realized derivatives (per Mcf)	$ 2.08	$ 2.38	$ 3.25
Natural gas, with realized derivatives (per Mcf)	$ 2.20	$ 2.47	$ 3.17
Operating Expenses (per BOE):			
Lease operating	$ 5.50	$ 5.20	$ 4.83
Transportation and processing	$ 0.88	$ 0.94	$ 1.25
Midstream operating	$ 2.75	$ 2.68	$ 2.58
Depletion, depreciation and amortization	$ 15.82	$ 15.59	$ 14.90
Taxes other than income	$ 3.65	$ 4.30	$ 4.59
General and administrative	$ 1.81	$ 2.04	$ 2.29

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2025 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford[1]	Haynesville	Cotton Valley[2]	Total
Annual Net Production Volumes					
Oil (MBbl)	43,664	34	—	1	43,699
Natural gas (Bcf)	183.3	—	7.8	0.2	191.3
Total oil equivalent (MBOE)[3]	74,216	38	1,290	37	75,581
Percentage of total annual net production	98.2 %	0.1 %	1.7 %	— %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	119,628	94	—	1	119,723
Natural gas (MMcf/d)	502.3	—	21.2	0.6	524.1
Total oil equivalent (BOE/d)	203,330	105	3,534	101	207,070
Average Sales Prices[4]					
Oil (per Bbl)	$ 64.99	$ 70.73	$ —	$ 60.44	$ 64.99
Natural gas (per Mcf)	$ 2.04	$ —	$ 3.11	$ 3.08	$ 2.08
Total oil equivalent (per BOE)	$ 43.27	$ 67.55	$ 18.67	$ 19.04	$ 42.85
Production Costs[5]					
Lease operating, transportation and processing (per BOE)	$ 6.40	$ 33.02	$ 3.84	$ 39.87	$ 6.38

(1) Includes 41 gross (32.3 net) wells from the Eagle Ford formation that were divested in the first quarter of 2025.

(2) Includes the Cotton Valley formation and shallower zones.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes midstream operating expenses, ad valorem taxes and oil and natural gas production taxes.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2024 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford[1]	Haynesville	Cotton Valley[2]	Total
Annual Net Production Volumes					
Oil (MBbl)	36,265	263	—	2	36,530
Natural gas (Bcf)	147.5	0.6	6.3	1.4	155.8
Total oil equivalent (MBOE)[3]	60,856	361	1,046	232	62,495
Percentage of total annual net production	97.4 %	0.6 %	1.7 %	0.3 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	99,086	719	—	3	99,808
Natural gas (MMcf/d)	403.1	1.6	17.2	3.8	425.7
Total oil equivalent (BOE/d)	166,273	986	2,859	633	170,751
Average Sales Prices[4]					
Oil (per Bbl)	$ 75.90	$ 75.64	$ —	$ 70.13	$ 75.89
Natural gas (per Mcf)	$ 2.40	$ 4.19	$ 1.95	$ 2.02	$ 2.38
Total oil equivalent (per BOE)	$ 51.05	$ 61.97	$ 11.67	$ 12.33	$ 50.31
Production Costs[5]					
Lease operating, transportation and processing (per BOE)	$ 5.97	$ 36.44	$ 5.46	$ 8.00	$ 6.14

(1) Includes 61 gross (41.0 net) wells from the Eagle Ford formation that were divested in 2024 and one well producing oil from the Austin Chalk formation in La Salle County, Texas that was divested in November 2024.

(2) Includes the Cotton Valley formation and shallower zones.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes midstream operating expenses, ad valorem taxes and oil and natural gas production taxes.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2023 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford[1]	Haynesville	Cotton Valley[2]	Total
Annual Net Production Volumes					
Oil (MBbl)	27,264	276	—	2	27,542
Natural gas (Bcf)	113.9	0.7	8.2	0.6	123.4
Total oil equivalent (MBOE)[3]	46,253	390	1,373	96	48,112
Percentage of total annual net production	96.1 %	0.8 %	2.9 %	0.2 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	74,697	755	—	5	75,457
Natural gas (MMcf/d)	312.1	1.9	22.6	1.5	338.1
Total oil equivalent (BOE/d)	126,720	1,068	3,761	264	131,813
Average Sales Prices[4]					
Oil (per Bbl)	$ 77.9	$ 76.1	$ —	$ 74.53	$ 77.88
Natural gas (per Mcf)	$ 3.32	$ 3.54	$ 2.23	$ 2.09	$ 3.25
Total oil equivalent (per BOE)	$ 54.10	$ 60.01	$ 13.39	$ 13.61	$ 52.91
Production Costs[5]					
Lease operating, transportation and processing (per BOE)	$ 5.88	$ 32.56	$ 4.56	$ 17.53	$ 6.08

(1) Includes one well producing oil from the Austin Chalk formation in La Salle County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas that was divested in September 2023.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes midstream operating expenses, ad valorem taxes and oil and natural gas production taxes.

Our total oil equivalent production of approximately 75.6 million BOE for the year ended December 31, 2025 increased 21% from our total oil equivalent production of approximately 62.5 million BOE for the year ended December 31, 2024. This increased production was primarily attributable to our delineation and development operations in the Delaware Basin throughout 2025, which offset our declining production in the Eagle Ford shale that was divested in the first quarter of 2025. Our average daily oil equivalent production for the year ended December 31, 2025 was 207,070 BOE per day, as compared to 170,751 BOE per day for the year ended December 31, 2024. Our average daily oil production for the year ended December 31, 2025 was 119,723 Bbl of oil per day, an increase of 20% from 99,808 Bbl of oil per day for the year ended December 31, 2024. Our average daily natural gas production for the year ended December 31, 2025 was 524.1 MMcf of natural gas per day, an increase of 23% from 425.7 MMcf of natural gas per day for the year ended December 31, 2024.

Our total oil equivalent production of approximately 62.5 million BOE for the year ended December 31, 2024 increased 30% from our total oil equivalent production of approximately 48.1 million BOE for the year ended December 31, 2023. This increased production was primarily due to the Ameredev Acquisition and to our delineation and development operations in the Delaware Basin throughout 2024, which offset our declining production in the Eagle Ford shale. Our average daily oil equivalent production for the year ended December 31, 2024 was 170,751 BOE per day, as compared to 131,813 BOE per day for the year ended December 31, 2023. Our average daily oil production for the year ended December 31, 2024 was 99,808 Bbl of oil per day, an increase of 32% from 75,457 Bbl of oil per day for the year ended December 31, 2023. Our average daily natural gas production for the year ended December 31, 2024 was 425.7 MMcf of natural gas per day, an increase of 26% from 338.1 MMcf of natural gas per day for the year ended December 31, 2023.

Producing Wells

The following table sets forth information relating to producing wells at December 31, 2025. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We had an approximate average working interest of 85% in all wells that we operated at December 31, 2025. For wells where we are not the operator, our working interests range from less than 1% to approximately 52% and average approximately 9%. In the table below, gross wells are the total number of producing wells in which we own a working interest and net wells represent the total of our fractional working interests owned in the gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin[1]	1,999	1,046.9	180	90.2	2,179	1,137.1
Northwest Louisiana:						
Haynesville	—	—	279	18.5	279	18.5
Cotton Valley[2]	—	—	64	38.7	64	38.7
Area Total	—	—	343	57.2	343	57.2
Total	1,999	1,046.9	523	147.4	2,522	1,194.3

(1) Includes 199 gross (76.4 net) vertical wells that were primarily acquired in multiple transactions.

(2) Includes the Cotton Valley formation and shallower zones.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2025, 2024 and 2023. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, primarily in the Delaware Basin, the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with SEC rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible (from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

	At December 31,[1]		
	2025	2024	2023
Estimated Proved Reserves Data:[2]			
Estimated proved reserves:			
Oil (MBbl)	375,980	361,842	272,277
Natural Gas (Bcf)	1,746.4	1,498.2	1,126.8
Total (MBOE)[3]	667,047	611,536	460,070
Estimated proved developed reserves:			
Oil (MBbl)	223,028	206,269	161,642
Natural Gas (Bcf)	1,109.8	963.2	782.7
Total (MBOE)[3]	407,987	366,797	292,097
Percent developed	61.2 %	60.0 %	63.5 %
Estimated proved undeveloped reserves:			
Oil (MBbl)	152,952	155,573	110,635
Natural gas (Bcf)	636.6	535.0	344.0
Total (MBOE)[3]	259,060	244,740	167,973
Standardized Measure[4] (in millions)	$ 6,986.6	$ 7,376.6	$ 6,113.5
PV-10[5] (in millions)	$ 8,237.8	$ 9,233.8	$ 7,704.1

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, Standardized Measure and PV-10 were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2025 were $61.82 per Bbl for oil and $3.39 per MMBtu for natural gas, for the 12 months ended December 31, 2024 were $71.96 per Bbl for oil and $2.13 per MMBtu for natural gas and for the 12 months ended December 31, 2023 were $74.70 per Bbl for oil and $2.64 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment and income tax expenses, discounted at 10% to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(5) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2025, 2024 and 2023 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by adding the discounted future income taxes associated with such reserves to the Standardized Measure. The discounted future income taxes at December 31, 2025, 2024 and 2023 were $1.25 billion, $1.86 billion and $1.59 billion, respectively.

Our estimated total proved oil and natural gas reserves increased 9% from 611.5 million BOE at December 31, 2024 to 667.0 million BOE at December 31, 2025. Our proved oil and natural gas reserves increased by 131.1 million BOE and we produced 75.6 million BOE during the year ended December 31, 2025. This increase in proved oil and natural gas reserves was primarily attributable to our delineation and development operations in the Delaware Basin during 2025. We increased our total proved oil and natural gas reserves by 3.3 million BOE as a result of acquisitions, divestitures and trades during 2025. We also added 135.0 million BOE in proved oil and natural gas reserves through extensions and discoveries during 2025, of which 23.0 million BOE resulted from new well locations turned to sales during 2025 to establish proved developed reserves and 112.0 million BOE resulted from new proved undeveloped locations identified as a result of drilling activities on our existing acreage in the Delaware Basin during 2025. Additionally, we realized approximately 7.2 million BOE in net downward revisions of prior estimates of proved reserves in 2025, which primarily included the removal of 22.8 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of our properties in the Delaware Basin, and 5.6 million BOE resulting from pricing updates, including the 14% decrease in oil prices, which was partially offset by the 59% increase in natural gas prices used to estimate total proved reserves at December 31, 2025, as compared to December 31, 2024, and 2.9 million BOE in expense updates. As we continue to develop our Delaware Basin assets, we may reclassify some or all of the 22.8 million BOE to proved reserves at a future date. These downward revisions at December 31, 2025 were partially offset by positive forecast updates of 24.1 million BOE.

Our proved oil reserves grew 4% from approximately 361.8 million Bbl at December 31, 2024 to approximately 376.0 million Bbl at December 31, 2025. Our proved natural gas reserves increased 17% from 1.50 Tcf at December 31, 2024 to 1.75

Tcf at December 31, 2025. Our proved reserves to production ratio at December 31, 2025 was 8.8, a decrease of 10% from 9.8 at December 31, 2024.

The Standardized Measure of our total proved oil and natural gas reserves decreased 5% from $7.38 billion at December 31, 2024 to $6.99 billion at December 31, 2025. The PV-10 of our total proved oil and natural gas reserves decreased 11% from $9.23 billion at December 31, 2024 to $8.24 billion at December 31, 2025. The decreases in our Standardized Measure and PV-10 are primarily a result of the lower unweighted arithmetic average oil prices, which were partially offset by the higher unweighted arithmetic average natural gas prices used to estimate proved reserves at December 31, 2025, as compared to December 31, 2024, partially offset by a 9% increase in our total proved oil and natural gas reserves at December 31, 2025, as compared to December 31, 2024. The unweighted arithmetic averages of first-day-of-the-month oil and natural gas prices used to estimate proved reserves at December 31, 2025 were $61.82 per Bbl and $3.39 per MMBtu, a decrease of 14% and an increase of 59%, respectively, as compared to average oil and natural gas prices of $71.96 per Bbl and $2.13 per MMBtu used to estimate proved reserves at December 31, 2024. Our total proved reserves were made up of 56% oil and 44% natural gas at December 31, 2025 and 59% oil and 41% natural gas at December 31, 2024. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see the preceding table.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2025.

	Proved Developed Reserves (MBOE)[1]
As of December 31, 2024	366,797
Extensions and discoveries	22,982
Net acquisitions of minerals-in-place	3,419
Revisions of prior estimates	12,799
Production	(75,575)
Conversion of proved undeveloped to proved developed	77,565
As of December 31, 2025	407,987

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Our proved developed oil and natural gas reserves increased 11% from 366.8 million BOE at December 31, 2024 to 408.0 million BOE at December 31, 2025. Our proved developed oil and natural gas reserves increased by 116.8 million BOE and we produced 75.6 million BOE during the year ended December 31, 2025, resulting in a net increase of 41.2 million BOE. We added 23.0 million BOE in proved developed reserves through extensions and discoveries during 2025, which resulted from new well locations drilled during 2025 to establish proved reserves. In addition, during 2025, we converted 77.6 million BOE of our proved undeveloped reserves to proved developed reserves primarily through our development activities in the Delaware Basin. We also increased our proved developed reserves by 3.4 million BOE at December 31, 2025 as a result of net property acquisitions, divestitures and trades completed during 2025. Additionally, we realized approximately 12.8 million BOE in net upward revisions of prior estimates of proved developed reserves in 2025, including positive forecast updates of 16.7 million BOE and ownership updates of 3.2 million BOE. These upward revisions were partially offset by downward revisions of 4.2 million BOE and 2.9 million BOE attributable to certain pricing and expense updates used to estimate proved developed reserves at December 31, 2025 and 2024, respectively.

Our proved developed oil reserves increased 8% from 206.3 million Bbl at December 31, 2024 to 223.0 million Bbl at December 31, 2025. Our proved developed natural gas reserves increased 15% from 963.2 Bcf at December 31, 2024 to 1.11 Tcf at December 31, 2025. Proved developed reserves constituted 61% of our total proved oil and natural gas reserves at December 31, 2025, as compared to 60% at December 31, 2024.

The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2025.

	Proved Undeveloped Reserves (MBOE)[1]
As of December 31, 2024	244,740
Extensions and discoveries	111,990
Net divestitures of minerals-in-place	(93)
Revisions of prior estimates	(20,012)
Conversion of proved undeveloped to proved developed	(77,565)
As of December 31, 2025	259,060

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Our proved undeveloped oil and natural gas reserves increased 6% from 244.7 million BOE at December 31, 2024 to 259.1 million at December 31, 2025. We added 112.0 million BOE in proved undeveloped reserves through extensions and discoveries during 2025, which resulted primarily from new proved undeveloped locations identified as a result of drilling activities on our existing acreage in the Delaware Basin during 2025. We also decreased our proved undeveloped reserves by 0.1 million BOE at December 31, 2025 as a result of net property acquisitions, divestitures and trades completed during 2025. Additionally, we realized approximately 20.0 million BOE in net downward revisions of prior estimates of proved undeveloped reserves in 2025, which included the removal of 22.8 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of our properties in the Delaware Basin and the removal of 3.2 million BOE and 1.4 million BOE for certain ownership and pricing updates at December 31, 2025 and 2024, respectively. These downward revisions were partially offset by positive forecast updates of 7.4 million BOE.

At December 31, 2025, we had no proved undeveloped reserves in our estimates that remained undeveloped for five years or more following their initial booking, and we currently have plans to use anticipated capital resources to develop the proved undeveloped reserves remaining as of December 31, 2025 within five years of booking these reserves. The following table sets forth, since 2022, proved undeveloped reserves converted to proved developed reserves during each year and the investments associated with these conversions (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			
	Oil (MBbl)	Natural Gas (Bcf)	Total (MBOE)[1]	Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
2022	22,515	95.3	38,403	434,336
2023	18,492	98.6	34,928	441,671
2024	34,857	118.4	54,598	685,163
2025	51,666	155.4	77,565	1,013,114
Total	127,530	467.7	205,494	$ 2,574,284

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth additional summary information by operating area with respect to our estimated net proved reserves at December 31, 2025.

	Net Proved Reserves[1]				
	Oil	Natural Gas	Oil Equivalent	Standardized Measure[2]	PV-10[3]
	(MBbl)	(Bcf)	(MBOE)[4]	(in millions)	(in millions)
Southeast New Mexico/West Texas:					
Delaware Basin	375,975	1,717.6	662,248	$ 6,969.0	$ 8,217.0
Northwest Louisiana					
Haynesville	—	25.8	4,302	23.8	28.1
Cotton Valley[5]	5	3.0	497	(6.2)	(7.3)
Area Total	5	28.8	4,799	17.6	20.8
Total	375,980	1,746.4	667,047	$ 6,986.6	$ 8,237.8

(1) Numbers in table may not total due to rounding.

(2) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2025 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by adding the discounted future income taxes associated with such reserves to the Standardized Measure. The discounted future income taxes at December 31, 2025 were approximately $1.25 billion.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Includes the Cotton Valley formation and shallower zones.

Technology Used to Establish Reserves

Under current SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible (from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The term "reasonable certainty" means a high degree of confidence that the quantities of oil and/or natural gas will be recovered. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include electric logs, radioactivity logs, core analyses, geologic maps and available pressure and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance methods. Certain new producing properties with little production history were forecasted using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecasted using either analogy and/or volumetric methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Individual asset teams are responsible for the day-to-day management of the oil and natural gas activities for each team's asset area. These asset teams are staffed with reservoir engineers who prepare reserves estimates at the end of each calendar quarter for the assets they manage. Our Vice President of Reservoir Engineering and the Reserves Team was primarily responsible for overseeing the preparation of our reserves estimates in 2025. He received Bachelor of Science degrees in both Petroleum Engineering and Mechanical Engineering from Texas Tech University, is a licensed Professional Engineer in the state of Texas and has over ten years of industry experience. Our Vice President of Reservoir Engineering and the Reserves Team works under the direct supervision of our Executive Vice President of Reservoir Engineering and Senior Asset Manager, who received a Bachelor of Science degree in Petroleum

Engineering from Texas A&M University and has over 15 years of industry experience. The Company has established internal controls over its reserves estimation processes and procedures to support the accurate and timely preparation and disclosure of reserves estimates in accordance with SEC and GAAP requirements. These controls include oversight of the reserves estimation processes by our internal reserves group as well as accounting and finance personnel. Following the preparation of our reserves estimates, these estimates are audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. Members of our executive committee and members of the Operations and Engineering Committee of our Board of Directors (the "Board") review the reserves report and our reserves estimation process, and the independent audit of our reserves is reviewed by other members of the Board as well.

Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2025.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin	284,700	171,200	69,900	41,300	354,600	212,500
Northwest Louisiana:						
Haynesville	16,200	8,900	—	—	16,200	8,900
Cotton Valley	15,800	14,800	—	—	15,800	14,800
Area Total[1]	18,500	17,300	—	—	18,500	17,300
Total	303,200	188,500	69,900	41,300	373,100	229,800

(1) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana.

Undeveloped Acreage Expiration

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2025 that will expire over the next five years by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates, the existing leases are renewed prior to expiration or continued operations maintain the leases beyond the expiration of each respective primary term. Undeveloped acreage expiring in 2031 and beyond totals 3,400 net acres, all of which is in the Delaware Basin. All of our leasehold in the Haynesville and Cotton Valley plays in Northwest Louisiana was held by existing production at December 31, 2025.

	Acres Expiring 2026		Acres Expiring 2027		Acres Expiring 2028		Acres Expiring 2029		Acres Expiring 2030	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:										
Delaware Basin[1]	11,000	8,400	15,900	14,200	33,900	10,000	3,800	3,800	1,500	1,500
Total	11,000	8,400	15,900	14,200	33,900	10,000	3,800	3,800	1,500	1,500

(1) Approximately 60% of the acreage expiring in the Delaware Basin in the next five years is associated with our Twin Lakes asset area in northern Lea County, New Mexico. We expect to hold or extend portions of certain expiring acreage in the Delaware Basin through our future drilling activities or by paying an additional lease bonus, where applicable.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations are conducted to maintain the respective leases in effect beyond the expiration of the primary term or production from the acreage has been established prior to such date, in which event the lease will remain in effect in most cases until the cessation of production in commercial quantities. We also have options to extend some of our leases through additional lease bonus payments prior to the expiration of the primary term of such lease. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third-party leases, or top leases, that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date or operations are not conducted to maintain the leases in effect beyond the primary term. As of December 31, 2025, our leases are primarily fee and state leases with primary terms of three to five years and federal leases with primary terms of ten years. We believe that our lease terms are similar to our competitors' lease terms as they relate to both primary term and royalty interests. At December 31, 2025, less than 1% of our proved oil and natural gas reserves would be impacted by the expirations of this undeveloped acreage.

Drilling Results

The following table summarizes our drilling activity for the years ended December 31, 2025, 2024 and 2023.

	Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	254	117.5	253	106.9	222	84.1
Dry	—	—	—	—	—	—
Exploration Wells						
Productive[1]	16	11.9	9	4.9	24	16.9
Dry	—	—	—	—	—	—
Total Wells						
Productive[2]	270	129.4	262	111.8	246	101.0
Dry	—	—	—	—	—	—

(1) All of these wells are extension wells.

(2) Includes three gross (1.5 net) vertical wells in 2024 and one gross (0.5 net) vertical well in 2023. We did not drill any vertical wells in 2025.

At December 31, 2025, we had a total of 150 gross (52.1 net) development wells and 11 gross (1.0 net) exploration wells that were in the process of being drilled, being completed or awaiting completion operations.

Marketing and Customers

Our crude oil is sold under both long-term and short-term oil purchase agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil and our heavier liquid products move up and down in direct correlation with the oil market as it reacts to supply and demand factors. The prices of our lighter liquid products move up and down independently of any relationship between the crude oil and natural gas markets. Transportation costs related to moving crude oil and liquids are also generally deducted from the price received for crude oil and liquids.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points to both unaffiliated independent marketing companies and unaffiliated midstream companies. The prices we receive are calculated based on various pipeline indices. When there is an opportunity to do so, we may have our natural gas processed at San Mateo's or third parties' processing facilities to extract liquid hydrocarbons from the natural gas. We are then paid for the extracted NGLs based on either a negotiated percentage of the proceeds that are generated from the sale of NGLs or other negotiated pricing arrangements using then-current market pricing less fixed rate processing, transportation and fractionation fees.

The prices we receive for our oil, natural gas and NGL production fluctuate widely. Factors that, directly or indirectly, cause price fluctuations include: the domestic and foreign supply of, and demand for, oil, natural gas and NGLs; the actions of the Organization of Petroleum Exporting Countries, Russia and certain other oil-exporting countries ("OPEC+") and state-controlled oil companies; the prices and availability of competitors' supplies of oil and natural gas; the price and quantity of foreign imports and exports; the impact of U.S. dollar exchange rates; domestic and foreign governmental regulations and taxes; speculative trading of, and other financial market conditions affecting, oil and natural gas futures contracts; the availability, proximity and capacity of gathering, processing and transportation systems for oil, natural gas and NGLs and gathering and disposal systems for produced water; the availability of refining capacity; the prices and availability of alternative fuel and energy sources; weather conditions and natural disasters, including floods, fires, tornadoes, droughts, hurricanes, tropical storms and severe cold weather; political conditions or conflicts in or affecting oil, natural gas and NGL producing regions or countries, including the United States, the Middle East, South America, Russia, Ukraine and China; the ongoing military conflicts between Russia and Ukraine and in the Middle East, as well as the related actions of U.S. and other governments and governmental organizations relating to oil, natural gas and NGLs, including through sanctions, embargoes, import restrictions and commodity price caps; the threat of terrorism and the impact of military action and civil unrest; public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate oil, natural gas and NGL operations, including hydraulic fracturing, flaring, venting and produced water handling and disposal activities; the level of global oil, natural gas and NGL inventories and exploration and production activity; the impact of energy conservation efforts; technological advances affecting energy consumption; tariffs, trade restrictions and other supply chain constraints; and overall worldwide economic conditions. Decreases in these commodity prices adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production occur from time to time due to downstream pipeline system failure, capacity issues and scheduled or unscheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations, if they

occur, curtail our production capabilities and ability to maintain a steady source of revenue. See "Risk Factors—Risks Related to our Financial Condition—Our success is dependent on the prices of oil, natural gas and NGLs. Low oil, natural gas and NGL prices and the continued volatility in these prices may adversely affect our financial condition and our ability to meet our capital expenditure requirements and financial obligations."

The prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate ("WTI") oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition, results of operations and cash flows. See "Risk Factors—Risks Related to our Financial Condition—A change in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could adversely affect our business, financial condition, results of operations and cash flows."

For the years ended December 31, 2025, 2024 and 2023, we had three significant purchasers that accounted for approximately 72%, 79% and 76%, respectively, of our total oil, natural gas and NGL revenues. If we lost one or more of these significant purchasers and were unable to sell our production to other purchasers on terms we consider acceptable, it could materially and adversely affect our business, financial condition, results of operations and cash flows. For further details regarding these purchasers, see Note 2 to the consolidated financial statements in this Annual Report. Such information is incorporated herein by reference.

Title to Properties

We endeavor to ensure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. While we rely upon the judgment of oil and natural gas lease brokers and landmen in ascertaining title for certain leasehold and mineral interest acquisitions, we typically obtain detailed title opinions prior to drilling an oil and natural gas well. Some of our acreage is subject to agreements that require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests may be contingent upon our satisfactory fulfillment of such obligations. Some of our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other similar burdens that we believe will not materially interfere with the use and operation of these properties or affect the value thereof. Generally, we intend to conduct operations, make lease rental payments or produce oil and natural gas from wells in paying quantities, where required, prior to expiration of various time periods in order to avoid lease termination. See "Risk Factors—Risks Related to our Financial Condition—We may incur losses or costs as a result of title deficiencies in the properties in which we invest."

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to customary encumbrances, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens or encumbrances will materially interfere with the use and operation of these properties in the conduct of our business. In addition, we believe that we have obtained sufficient right-of-way grants and permits from public authorities and private parties for us to operate our business.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter and decrease during summer. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are affected more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. Certain of our drilling, completion and other operations are also subject to seasonal limitations where equipment may not be available during periods of peak demand or where weather conditions and events result in delayed operations. See "Risk Factors—Risks Related to our Operations—Because our reserves and production are concentrated in a few core areas, problems with production in and markets for a particular area could have a material impact on our business."

Competition

The oil and natural gas industry is highly competitive. We compete with major and independent oil and natural gas companies for exploration and development opportunities and acreage acquisitions as well as drilling rigs and other equipment and labor required to drill, complete, operate and develop our properties. We also compete with public and private midstream companies for natural gas gathering and processing opportunities, as well as produced water gathering and disposal and oil gathering and transportation activities in the areas in which we operate. In addition, competition in the midstream industry is based on the geographic location of facilities, business reputation, reliability and pricing arrangements for the services offered. San Mateo competes with other midstream companies that provide similar services in their areas of operations, and such companies may have legacy relationships with producers in those areas and may have a longer history of efficiency and reliability.

Many of our competitors have substantially greater financial resources, staffs, facilities and other resources. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. These competitors may be willing and able to pay more for drilling rigs, leasehold and mineral acreage, productive oil and natural gas properties or midstream facilities and may be able to identify, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our competitors may also be able to afford to purchase and operate their own drilling rigs and hydraulic fracturing equipment.

Our ability to drill and explore for oil and natural gas, acquire properties and provide competitive midstream services will depend upon our ability to conduct operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment. In addition, many of our competitors may have a longer history of operations.

The oil and natural gas industry also competes with other energy-related industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. See “Risk Factors—Risks Related to Third Parties—Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas, provide midstream services and secure trained personnel, and our competitors may use superior technology and data resources that we may be unable to afford.”

Environmental

Emissions Mitigation

We work to maximize the percentage of natural gas we capture from the production of each of our wells. Newly drilled wells are connected to natural gas pipelines that we expect to have sufficient reliability and capacity to support our production operations. We connect many of our wells to San Mateo’s natural gas gathering systems. This greatly reduces the need to flare natural gas. We design our production facilities and use advanced natural gas capture and control equipment during production, including the use of vapor recovery units (“VRU”), to maximize natural gas capture. VRUs enable us to collect and compress natural gas from lower pressure sources that might otherwise be flared. This reduces emissions and increases the volumes of natural gas that we can sell. When possible, we use centralized tank batteries and commingle production from multiple wells to take advantage of economies of scale to use these VRUs and other specialized equipment in our production facilities.

Our field employees monitor our facilities and inspect for any necessary repairs or maintenance. In addition, we have implemented a leak detection and repair program that involves scheduled inspections for natural gas capture. These inspections are bolstered by our use of optical gas imaging cameras, which help to identify potential emissions that may not be visible to the naked eye. We have also implemented real-time remote monitoring of vapor control systems through Supervisory Control and Data Acquisition (“SCADA”) equipment at a number of our larger production facilities. These inspections are being conducted regularly, both by our staff and by third-party contractors, more frequently and at more locations than federal and state regulations require.

Additionally, we connect many of our production facilities to electric grid power. Connecting to grid power allows us to forego using internal combustion-powered generators on-site, which further reduces emissions.

Water Management

Using improving technologies, where feasible, we are able to take produced water from our existing wells and from third-party systems, treat the water and then reuse that water in our completions operations on new wells. Use of recycled water saves significant amounts of fresh water that would otherwise have been used for hydraulic fracturing operations. As well as conserving fresh water, our use of recycled water in our completions operations reduces the amount of produced water that must be disposed. It also results in significant cost savings and efficiencies. In addition to using recycled water where feasible, we also use other sources of non-fresh water, which reduces the volume of fresh water used for our operations.

Land Stewardship

When feasible, we attempt to reduce our surface footprint by batch drilling wells and drilling longer laterals, both of which result in fewer required drilling pads, and by working with the various regulatory agencies, including the New Mexico Oil Conservation Division (the "NMOCD") and the U.S. Department of Interior Bureau of Land Management ("BLM"), to obtain approval to commingle production from different wells into centralized tank batteries. We also take steps to ensure we conduct our operations in locations that minimize any potential disturbance to the habitats around which we operate. As part of that effort, we have entered into voluntary agreements with the U.S. Fish and Wildlife Service (the "USFWS") and the Center of Excellence for Hazardous Materials Management to observe operational restrictions designed to protect certain wildlife. Additionally, for our federal locations and as otherwise warranted, we conduct wildlife, biology and archeology surveys and undertake reviews for caves, karsts and potential hydrology considerations.

During 2025, 97% of our gross operated oil production and 99% of our gross operated water production were connected to pipelines. In addition to the financial benefits to us and our stakeholders of connecting oil and produced water to pipelines, these pipeline connections have many other benefits, including the reduction in the number of trucks needed to transport the oil and produced water.

Regulation

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production, midstream and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial monetary penalties or delay or suspension of operations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations.

The states in which we operate require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. The states in which we operate also have laws, rules and regulations addressing conservation of oil and natural gas and other matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing and setbacks, the surface use and restoration of properties upon which wells are drilled, the prohibition, restriction or limitation of emissions, venting or flaring natural gas, the sourcing and disposal of water used and produced in the drilling and completion process, the seismicity that may be related to salt water disposal wells and the plugging and abandonment of wells. While not presently the case in the states in which we operate, some states restrict production to the market demand for oil and natural gas or prescribe ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases. BLM leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. These operations are also subject to BLM rules regarding engineering and construction specifications for production facilities, ability to commingle production, safety procedures, the valuation of production, the payment of royalties, the removal of facilities, the posting of bonds, hydraulic fracturing, the control of air emissions and other areas of environmental protection. These rules could result in increased compliance costs for our operations, which in turn could have a material adverse effect on our business and results of operations. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. Permitting for oil and natural gas activities on federal lands can take significantly longer than the permitting process for oil and natural gas activities not located on federal lands. In addition, government disruptions, such as a shutdown of the U.S. federal government resulting from the failure to pass budget appropriations, adopt continuing funding resolutions or raise the debt ceiling, could delay or halt the granting and renewal of such permits or other licenses, approvals or certificates required to conduct our operations. Delays in obtaining necessary permits or other approvals can disrupt our operations and have a material adverse effect on our business.

Oil and natural gas exploration and production activities on federal lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an

environmental assessment of impacts that are "reasonably foreseeable" and have a "reasonably close causal relationship" to the agency action under review 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 at the Department of the Interior has followed regulations issued by the Council on Environmental Quality ("CEQ") for many years. However, recent court rulings, including a 2024 decision by the United States Court of Appeals for the District of Columbia, have held that CEQ lacks legal authority to issue binding regulations governing the NEPA process. In addition, CEQ rescinded its NEPA regulations in February 2025, and as a result, each government agency impacted by NEPA is establishing its own processes and procedures. 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 even halt development of future oil and natural gas projects subject to review under NEPA.

In 2019, 2020 and 2021, an environmental group filed multiple lawsuits in federal district courts in New Mexico and the District of Columbia challenging certain BLM lease sales, including lease sales in which we purchased leases in New Mexico (the "Lease Sale Litigation"). The Lease Sale Litigation challenged the BLM's decision to hold the lease sales based on alleged defects in the NEPA reviews conducted in conjunction with those sales. These lawsuits were dismissed in 2021 and 2022. In connection with these dismissals, in February 2022, the BLM announced an internal policy of delaying approval of drilling permits associated with the leases that were subject to the Lease Sale Litigation, including the dismissed New Mexico case, while the BLM conducted additional NEPA analyses. In September 2025, the BLM issued a Supplemental NEPA Analysis, which has not yet been finalized, proposing to uphold the previously issued leases. The outcome of BLM's NEPA review and any future litigation regarding the leases at issue and any related drilling permits is uncertain. In addition, in February 2023, the Tenth Circuit Court of Appeals ruled that certain BLM drilling permits for wells in the Chaco region of New Mexico were issued without adequate NEPA review, and BLM agreed to conduct additional NEPA analysis in response to this litigation. Each of these pending lawsuits and NEPA reviews, as well as any process changes that the BLM may implement in response, could delay lease sales and the approval of drilling permits, though the ultimate impact is uncertain.

In November 2022, the Environmental Protection Agency (the "EPA") suggested increasing the value of the social cost of greenhouse gases from $51 per metric ton to $190 per metric ton, and in December 2023, the EPA used $190 per metric ton as the social cost of greenhouse gases in its final rule revising New Source Performance Standards ("NSPS") and Emission Guidelines for greenhouse gas and volatile organic compound emissions in the oil and gas sector. As part of this final rulemaking, the EPA published a peer-reviewed report on the updated social cost of greenhouse gases estimates. However, in January 2025, the Trump administration revoked the Biden administration's executive order regarding the social cost of greenhouse gases, withdrew the social cost of greenhouse gases estimates and directed the EPA administrator to consider issuing guidance eliminating the social cost of carbon calculation from any federal permitting or regulatory decision. In March 2025, the EPA administrator announced that the EPA is reconsidering the social cost of greenhouse gases estimates, and in May 2025, the White House Office of Management and Budget directed agencies to limit their consideration of greenhouse gas emissions only to that plainly required in their governing statutes. Future EPA rulemakings may reestablish the previous social cost of greenhouse gases estimates or incorporate new estimates developed in the future and potentially result in more stringent rules and regulations affecting the oil and gas sector.

On February 18, 2026, the EPA published a final rule rescinding its prior 2009 finding that six greenhouse gases in the atmosphere—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride—may reasonably be anticipated to endanger public health and welfare under the Clean Air Act (the "CAA"), commonly known as the "Endangerment Finding," which underpins the EPA's regulation of greenhouse gas emissions. The rescission has been challenged in court, which could result in the rescission being stayed, overturned or limited in scope or effect. If the rescission remains in effect, the EPA may seek in the future to repeal or lessen the stringency of regulations affecting the oil and natural gas industry that are based, at least in part, on the Endangerment Finding. Further, it is possible that efforts to regulate greenhouse gases at the national level in the United States, which could include reconsidering the Endangerment Finding, could occur in the future. The ultimate outcome and long-term effect of the rescission of the Endangerment Finding, as well as its impact on regulation of the oil and natural gas industry, remains uncertain.

In April 2024, the BLM finalized a new rule designed to reduce natural gas waste through limitation of certain oil and natural gas production activities and the imposition of more stringent royalty obligations on natural gas that is "avoidably lost" during operations. Enforcement of the rule in Texas, North Dakota, Montana, Wyoming, and Utah was enjoined by the North Dakota federal district court, and the appeal of that injunction to the U.S. Court of Appeals for the Eighth Circuit has been held in abeyance since February 14, 2025. The Department of the Interior announced it is evaluating whether to suspend, revise, or rescind the 2024 waste rule, and in November 2025, announced that it will delay enforcement of provisions of the rule that had been scheduled to take effect in December 2025. The ultimate outcome of this process, including possible financial costs and any adverse impacts on our oil and natural gas operations, is uncertain.

The impact of these and similar federal actions related to the oil and natural gas industry remains unclear, and should limitations or prohibitions be imposed or continue to be applied, our oil and natural gas operations on federal lands could be adversely impacted. See "Risk Factors—Risks Related to Laws and Regulations—Approximately 33% of our leasehold and

mineral acres in the Delaware Basin is located on federal lands, which are subject to administrative permitting requirements and potential federal legislation, regulation and orders that may limit or restrict oil and natural gas operations on federal lands."

Pipeline Regulation

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 (the "NGA"), as well as under Section 311 of the Natural Gas Policy Act of 1978 (the "NGPA"). Natural gas gathering facilities are exempt from the jurisdiction of FERC under section 1(b) of the NGA, and intrastate crude oil pipeline facilities are not subject to FERC's jurisdiction under the Interstate Commerce Act (the "ICA"). State regulation of natural gas gathering facilities and intrastate crude oil pipeline facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements or complaint-based rate regulation. 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 FERC jurisdiction. San Mateo's crude oil gathering and transportation system in the Rustler Breaks asset area in Eddy County, New Mexico and the Greater Stebbins Area (the "Rustler Breaks Oil Pipeline System"), which includes approximately 70 miles of various diameter crude oil pipelines from origin points in Eddy County, New Mexico to an interconnect with Plains, is subject to FERC jurisdiction. Our crude oil gathering and transportation pipelines with origin points from Lea County, New Mexico to various interconnections with third parties (the "Trophy Pipeline System") are also subject to FERC jurisdiction. We believe that the other crude oil pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as an intrastate facility not subject to FERC jurisdiction.

In 2005, Congress enacted the Energy Policy Act of 2005 (the "Energy Policy Act"). The Energy Policy Act, among other things, amended the NGA to prohibit market manipulation in connection with the purchase or sale of natural gas or the purchase or sale of natural gas transportation services subject to FERC jurisdiction by any entity and to direct FERC to facilitate transparency in the market for the sale or transportation of natural gas in interstate commerce. The Energy Policy Act also significantly increased the penalties for violations of, among other things, the NGA, the NGPA or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties and disgorgement, we may also be subject to third-party damage claims.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies (and to a limited extent by FERC, as noted above). 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. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that regulation in any states in which we operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.

The Rustler Breaks Oil Pipeline System and the Trophy Pipeline System are subject to regulation by FERC under the ICA and the Energy Policy Act of 1992 (the "EP Act"). The ICA and its implementing regulations give FERC authority to regulate the rates charged for service on interstate common carrier pipelines and generally require the rates and practices of interstate crude oil pipelines to be just, reasonable, not unduly discriminatory and not unduly preferential. The ICA also requires tariffs that set forth the rates an interstate crude oil pipeline company charges for providing transportation services on its FERC-jurisdictional pipelines, as well as the rules and regulations governing these services, to be maintained on file with FERC and posted publicly. The EP Act and its implementing regulations also generally allow interstate crude oil pipelines to annually index their rates up to a prescribed ceiling level and require that such pipelines index their rates down to the prescribed ceiling level if the index is negative.

The price we receive from the sale of oil and NGLs will be affected by the availability, terms and cost of transportation of such products to market. As noted above, under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates are subject to regulations promulgated by state regulatory commissions, which vary from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

In 2007, the Energy Independence & Security Act of 2007 (the "EISA") went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder.

The Pipeline and Hazardous Materials Safety Administration (the "PHMSA") imposes pipeline safety requirements on regulated pipelines and gathering lines pursuant to its authority under the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act, each as amended. The Rustler Breaks Oil Pipeline System and the Trophy Pipeline System are subject to PHMSA oversight. The Department of Transportation, through PHMSA, has established rules regarding integrity

management programs for interstate oil pipelines, including the Rustler Breaks Oil Pipeline System and the Trophy Pipeline System. In recent years, pursuant to these laws and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and PIPES Act of 2016, PHMSA has expanded its regulation of gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. Certain of our natural gas gathering lines are federally "regulated gathering lines" subject to PHMSA requirements. On April 8, 2016, PHMSA published a notice of proposed rulemaking that would amend existing integrity management requirements, expand assessment and repair requirements in areas with medium population densities and extend regulatory requirements to onshore natural gas gathering lines that are currently exempt. To enact the changes outlined in the notice of proposed rulemaking, PHMSA enacted three separate rules (together known as the "Mega Rule"). The first part of the Mega Rule was finalized in October 2019 and requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming the maximum allowable operating pressure. In addition, the rule updates reporting and records retention standards for gas transmission pipelines. PHMSA issued the second part of the Mega Rule in November 2021, extending the federal safety requirements to onshore gas gathering pipelines with large diameters and high operating pressures. PHMSA issued the third part of the Mega Rule in August 2022, which is applicable to onshore gas transmission pipelines and clarifies integrity management regulations, expands corrosion control requirements, mandates inspections after extreme weather events and updates existing repair criteria for both High Consequence Areas ("HCA") and non-HCA pipelines. In September 2023, PHMSA issued a proposed rule applicable to gas transmission and distribution and gathering pipelines, which would require updates to emergency response plans and other safety practices. In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. See "Risk Factors—Risks Related to Laws and Regulations—We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations."

Additional expansion of pipeline safety requirements or our operations could subject us to more stringent or costly safety standards, which could result in increased operating costs or operational delays.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur.

In addition, from time to time there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals at the federal level. Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such changes include (i) the repeal of the percentage depletion allowance for certain oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production or manufacturing activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. Any such changes in federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and natural gas exploration and development, and any such changes could negatively affect our financial condition, results of operations and cash flows.

Changes to state or federal tax laws could adversely affect our business and our financial results. See "Risk Factors—Risks Related to Laws and Regulations—We are subject to federal, state and local taxes and may become subject to new taxes or have eliminated or reduced certain federal income tax deductions currently available with respect to oil and natural gas exploration and production activities as a result of future legislation, which could adversely affect our business, financial condition, results of operations and cash flows."

Underground Injection and Hydraulic Fracturing

We own and operate underground injection wells throughout our areas of operation. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. Underground injection allows us to safely and economically dispose of produced water. The Safe Drinking Water Act (the "SDWA") establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. In addition, the Railroad Commission of Texas (the "RRC") and the NMOCD require injected fluids to be confined to a permitted injection interval to aid in the protection of potentially productive intervals. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. Failure to obtain, or abide by the requirements for the issuance of, necessary permits could subject us to civil and/or criminal enforcement actions and penalties. In addition, in some instances, the operation of underground injection wells has been alleged to cause

earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells.

In addition, a number of lawsuits have been filed in some states against others in our industry alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states, including New Mexico and Texas, have imposed additional regulatory or permitting requirements, including requirements regarding the permitting of salt water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells and, in some instances, allow the agency to modify, suspend, or terminate existing operating permits for disposal wells. The potential adoption of federal, state and local legislation and regulations intended to address induced seismicity in the areas in which we operate could restrict our drilling and production activities and our midstream operations, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays that could, in turn, materially impact our production volumes, revenues, reserves, cash flows and availability under our secured revolving credit facility (the "Credit Agreement").

We use hydraulic fracturing as a means to maximize the recovery of oil and natural gas in almost every well that we drill and complete. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately half of the total well costs for our horizontal wells are attributable to overall completion activities, which are primarily focused on hydraulic fracture treatment operations. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See "Risk Factors—Risks Related to Laws and Regulations—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays."

The process of hydraulic fracturing is typically regulated by state oil and natural gas commissions. Various policy makers, regulatory agencies and political candidates at the federal, state and local levels have proposed restrictions on hydraulic fracturing, including its outright prohibition. Restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce. Some states and localities have placed additional regulatory burdens upon hydraulic fracturing activities and, in some areas, severely restricted or prohibited those activities. For example, in recent years, various bills have been introduced in the New Mexico legislature to place a moratorium on, ban or otherwise restrict hydraulic fracturing, including prohibiting the injection of fresh water in such operations. In addition, separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to induced seismicity. The scientific community and regulatory agencies at all levels are studying the possible linkage between oil and natural gas activity and induced seismicity, and some state regulatory agencies have modified their regulations or guidance to mitigate potential causes of induced seismicity. Hydraulic fracturing is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level imposing any restrictions on the use of hydraulic fracturing, this could have a material adverse impact on our financial condition, results of operations and cash flows. Additional burdens upon hydraulic fracturing, such as reporting or permitting requirements, would result in additional expense and delay in our operations. See "Risk Factors—Risks Related to Laws and Regulations—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays" and "Risk Factors—Risks Related to Laws and Regulations—Approximately 33% of our leasehold and mineral acres in the Delaware Basin is located on federal lands, which are subject to administrative permitting requirements and potential federal legislation, regulation and orders that may limit or restrict oil and natural gas operations on federal lands."

Environmental, Health and Safety Regulation

The exploration, development, production, gathering and processing of oil and natural gas are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, drilling, completing and operating oil and natural gas wells, midstream facilities and produced water injection and disposal wells. Our activities are subject to a variety of environmental laws and regulations, including: the Oil Pollution Act of 1990 (the "OPA 90"), the Clean Water Act (the "CWA"), the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the CAA and the Occupational Safety and Health Act ("OSHA"), as well as comparable state statutes and regulations. We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials ("NORM") that may result from our oil and natural gas operations. Administrative, civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations, and violations and liability with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, may require notice to stakeholders of proposed and ongoing operations, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. These laws, rules and regulations may also restrict the production rate of oil and natural gas or limit the injection of produced water into disposal wells below the rates that would otherwise be possible. We expect to remain in compliance in all material respects with currently applicable environmental laws and regulations and do not expect that these laws and regulations will have a material adverse impact on us.

The OPA 90 and its regulations impose requirements on "responsible parties" related to the prevention of crude oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal and remediation costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action.

The CWA and comparable state laws impose restrictions and strict controls regarding the discharge of produced waters, fill materials and other materials into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into certain state and federal waters and to conduct construction activities in those waters and wetlands. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges.

CERCLA, also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on various classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. 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 hazardous substances released into the environment. Although CERCLA generally exempts petroleum from the definition of hazardous substances, our operations may, and in all likelihood will, involve the use or handling of materials that are classified as hazardous substances under CERCLA. Each state also has environmental cleanup laws analogous to CERCLA.

RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. Not all of the wastes we generate fall within these exemptions. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than nonhazardous wastes.

The CAA, as amended, restricts the emission of air pollutants from many sources, including oil and natural gas production. In addition, certain states have comparable legislation, which may be more restrictive than the CAA. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties

for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. On August 16, 2022, the IRA created the Methane Emissions Reduction Program to incentivize methane emission reductions and impose a waste emissions charge on greenhouse gas emissions from certain facilities that exceed specified emissions levels. However, the OBBBA delayed implementation of the waste emissions charges for the oil and gas industry until 2034. See "Risk Factors—Risks Related to Laws and Regulations—New regulations on all emissions from our operations could cause us to incur significant costs."

Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and "represent a progression" in their intended nationally determined contributions ("NDC"), which set greenhouse gas emission reduction goals, every five years beginning in 2020. The United States exited the Paris Agreement in November 2020, but rejoined the agreement effective February 19, 2021. In April 2021, the United States made its NDC submittal, setting an emissions reduction goal of a 50 to 52% reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030. Further, in November 2021, the United States and other countries entered into the Glasgow Climate Pact, which included a range of measures designed to address climate change, including the phase-out of fossil fuel subsidies, reducing methane emissions 30% by 2030 and cooperating toward the advancement of the development of alternative sources of energy. However, the Trump administration changed course on the United States' participation in international climate initiatives. In January 2025, the Trump administration issued an executive order directing the U.S. Ambassador to the United Nations to immediately submit formal written notification of the U.S.'s withdrawal from the Paris Agreement and any agreement, pact, accord or similar commitment made under the United Nations Framework Convention on Climate Change, which would include the Glasgow Climate Pact, and the U.S. Ambassador to the United Nations has submitted formal notifications to the United Nations of such withdrawals. The withdrawal of the United States from the Paris Agreement took effect on January 27, 2026. Certain states, including New Mexico, joined the U.S. Climate Alliance and have issued regulations aimed at supporting the goals of the Paris Agreement.

In January 2019, New Mexico's governor signed an executive order declaring that New Mexico would support the goals of the Paris Agreement by joining the U.S. Climate Alliance, a bipartisan coalition of governors committed to reducing greenhouse gas emissions consistent with the goals of the Paris Agreement. The stated objective of the executive order is to achieve a statewide reduction in greenhouse gas emissions of at least 45% by 2030 as compared to 2005 levels. The executive order also requires New Mexico regulatory agencies to create an "enforceable regulatory framework" to ensure methane emission reductions. The New Mexico Environment Department ("NMED") and the NMOCD both issued regulations in response to the governor's executive order, limiting some aspects of oil and gas operations in the state.

In January 2025, the NMED announced that, due to budget constraints, the NMED Cabinet Secretary will issue a temporary emergency rule to suspend deadlines to issue air permits. Air permits are required for the construction of new oil and gas production facilities or the modification of existing facilities in New Mexico. Whether this announcement will result in meaningful delays or cancellation of our permit applications is uncertain. Any interruption in our ability to timely obtain air permits could result in delays in or an inability to proceed with our development plans for our oil and natural gas operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or operating requirements could materially adversely affect our operations and financial condition, as well as those of the oil and natural gas industry in general. For example, on March 8, 2024, the EPA issued a final rule to regulate emissions from oil and natural gas sources that includes NSPS to limit greenhouse gas and volatile organic compound emissions for new, modified or reconstructed sources, as well as emissions guidelines for states to follow when establishing plans to limit methane emissions from existing sources. On December 3, 2025, the EPA issued a final rule extending certain compliance deadlines in the March 8, 2024 rule. Additionally, on November 17, 2023, the EPA issued a final rule that enables states to implement more stringent methane emissions standards than the federal guidelines require. As another example, in April 2024, the EPA issued a final consent decree that established a December 10, 2024 deadline for the EPA to review and propose revisions to the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for oil and natural gas production facilities and natural gas transmission and storage facilities, which may require us to make additional changes to our operations. The EPA has not yet proposed any such revisions.

On February 18, 2026, the EPA published a final rule rescinding the Endangerment Finding, which underpins the EPA's regulation of greenhouse gas emissions. The rescission has been challenged in court, which could result in the rescission being stayed, overturned or limited in scope or effect. See "Regulation—Oil and Natural Gas Regulation" for additional information.

Legislative and regulatory initiatives related to climate change and greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas. See "Risk Factors—Risks Related to Laws and Regulations—Legislation or regulations restricting emissions of greenhouse gases or promoting the development of alternative sources of energy could result in increased operating costs and reduced demand for the oil, natural gas and NGLs we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in

preparing for or responding to those effects" and "Risk Factors—Risks Related to Laws and Regulations—New regulations on all emissions from our operations could cause us to incur significant costs."

In the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil, produced water or other materials may occur, and we may incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states, including Texas, New Mexico and Louisiana, have enacted regulations governing the handling, treatment, storage and disposal of NORM.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the "community right-to-know" regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

The Endangered Species Act ("ESA") was 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. For example, when the USFWS issues a final rule listing a species as endangered or threatened, the USFWS must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in material restrictions on land use and may materially impact oil and natural gas development. Our oil and natural gas operations in certain of our operating areas could also be adversely affected by seasonal or permanent restrictions on drilling activity designed to protect certain wildlife in the Delaware Basin and other areas in which we operate and our ability to maximize production from our leases may be adversely impacted by these restrictions. See "Risk Factors—Risks Related to Laws and Regulations—We are subject to government regulation and liability, including complex environmental laws, which could require significant expenditures."

We have not in the past been, and do not anticipate in the near future to be, required to expend amounts that are material in relation to our total capital expenditures as a result of environmental laws and regulations, but since these laws and regulations are periodically amended, we are unable to predict the ultimate cost of compliance. We have no assurance that more stringent environmental laws and regulations will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. The overall trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly permitting, emissions control, waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial condition. We may be unable or unwilling to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we have no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. See "Risk Factors—Risks Related to Laws and Regulations—We are subject to government regulation and liability, including complex environmental laws, which could require significant expenditures."

Oil and natural gas exploration and production operations and other activities have been conducted on some of our properties by previous owners and operators. Operations by previous owners and operators may not have been conducted in compliance with applicable rules and regulations, and materials from these operations may remain on some of the properties, and, in some instances, require remediation. In addition, we occasionally must agree to indemnify sellers and buyers, respectively, of producing properties against some of the liability for environmental claims or violations associated with the properties we purchase or sell, respectively. Moreover, we will be able to control directly the operations of only those wells we operate. Despite our lack of control over wells owned partly by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us. While we do not believe that costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, we cannot provide any assurances that these costs will not result in material expenditures that adversely affect our profitability.

We maintain insurance against some, but not all, potential risks and losses associated with our industry and operations. We generally do not carry business interruption insurance other than with respect to our midstream business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows. See "Risk Factors—Risks Related to our Operations—Insurance against all operational risks is not available to us."

Office Location

Our corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240.

Human Capital

At December 31, 2025, we had 483 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, including in the areas of geology and geophysics, land, production and midstream operations, construction, design, well site surveillance and supervision, permitting and environmental assessment, legal and income tax preparation and accounting services. Independent contractors, at our request, drill and complete all of our wells and usually perform field and on-site production operation services for us, including midstream services, facilities construction, pumping, maintenance, dispatching, inspection and testing. If significant opportunities for company growth arise and require additional management and professional expertise, we will seek to employ qualified individuals to fill positions where that expertise is necessary to develop those opportunities.

Employee Recruiting, Retention and Professional Development

Our employees are our most important asset. We have invested the time, attention and resources necessary to recruit, retain and develop an extraordinary team. We offer a comprehensive compensation package with base pay, discretionary bonus and equity incentive opportunities, paid time off, 401(k) matching contributions, an employee stock purchase plan and an affordable and comprehensive health insurance program, among other benefits. We also provide employees the opportunity to have significant responsibility and daily interaction with our executive management and team leaders.

We encourage continuing education and study, requiring every employee to complete at least 40 hours of professional training annually. In 2025, for example, our employees completed approximately 26,800 hours of continuing education and study, equating to approximately 56 hours per employee. We also have a leadership program that fosters the development and growth of many of our staff with meetings and opportunities to enhance their leadership skills.

We respect cultural diversity and do not tolerate harassment or discrimination of any kind, including discrimination based on race, color, ethnicity, religion, gender, sexual orientation, gender identity, age, national origin, disability and veteran or marital status.

Proactive Safety Culture

We are proud to have a company culture that emphasizes safety throughout our operations. Our Health, Safety and Environmental ("HSE") group and our experienced field and office staff involved in our drilling, completion, production and midstream operations proactively work to minimize safety risks and address any potential areas of concern.

We emphasize the importance of recruiting and maintaining a quality HSE group, and we believe it is important that our HSE group has actual hands-on experience in the field to understand the challenges and issues that can arise. Our HSE group's experience allows us to understand the technical issues faced by our field employees and contractors, as well as maintain an open dialogue with community leaders in the areas we operate about potential safety issues and mitigation efforts.

Available Information

Our Internet website address is *www.matadorresources.com*. We make available, free of charge, through our website, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our Audit Committee, Executive Committee, Nominating and Corporate Governance Committee and Strategic Planning and Compensation Committee, our Code of Ethics and Business Conduct for Officers, Directors and Employees and information regarding certain of our sustainability practices, investor presentations, press releases and shareholder communications are available through our website, and we also intend to disclose any amendments to our Code of Ethics and Business Conduct, or waivers to such code on behalf of our Chief Executive Officer, Chief Financial Officer or Chief Accounting Officer, on our website. All of these corporate governance materials are available free of charge and in print to any shareholder who provides a written request to the Corporate Secretary at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. The contents of our website are not intended to be incorporated by reference into this Annual Report or any other report or document we file and any reference to our website is intended to be an inactive textual reference only.

Item 1A. Risk Factors.

Summary of Risk Factors

The following is a summary of some of the risks and uncertainties that could materially adversely affect our business, financial condition, results of operations and cash flows. You should read this summary together with the more detailed risk factors contained below.

Risks Related to our Financial Condition

- Our success is dependent on the prices of oil, natural gas and NGLs, the volatility of which may adversely affect our financial condition.
- Our industry and the broader U.S. economy have experienced higher than expected inflationary pressures in recent years.
- We cannot predict the impact of armed conflicts, including the ongoing military conflicts between Russia and Ukraine and in the Middle East.
- Our business requires substantial capital expenditures that may exceed our cash flows from operations and potential borrowings.
- Our oil and natural gas reserves are estimated, and significant inaccuracies in our oil and natural gas reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- The calculated present value of future net revenues from our proved oil and natural gas reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.
- Approximately 39% of our total proved reserves at December 31, 2025 consisted of undeveloped and developed non-producing reserves, and those reserves may not ultimately be developed or produced.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline.
- We may be required to write down the carrying value of our proved properties under accounting rules.
- Hedging transactions, or the lack thereof, may limit our potential gains and could result in financial losses.
- Changes in price differentials between benchmark prices of oil and natural gas and the wellhead price we receive for our production could adversely affect us.
- Our failure to identify, complete or integrate future acquisitions successfully could reduce our earnings and hamper our growth.
- We may purchase properties or midstream assets with liabilities or risks that we did not know about or assess correctly.
- We may incur losses or costs as a result of title deficiencies in the properties in which we invest.
- Our ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond our control, and in certain cases we may be required to retain liabilities for certain matters.

Risks Related to our Liquidity

- We may not be able to generate sufficient cash to fund our capital expenditures, service all of our indebtedness and pay dividends to our shareholders, and we may incur additional indebtedness, which could reduce our financial flexibility.
- The borrowing base under our Credit Agreement is subject to periodic redetermination, and we are subject to interest rate risk under our Credit Agreement and the San Mateo Credit Facility.
- The terms of the agreements governing our outstanding indebtedness may restrict our current and future operations.
- Our credit rating may be downgraded, which could reduce our financial flexibility.
- Dividend payments and repurchases of common stock are at the discretion of our Board of Directors and subject to numerous factors.

Risks Related to our Operations

- Drilling for and producing oil, natural gas and NGLs is highly speculative and involves a high degree of operational and financial risk.
- Our operations are subject to operational hazards and risks, and insurance against all such risks is not available to us.
- Our reserves and production are concentrated in a few core areas.
- There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques.
- Certain 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 of other operators.
- Multi-well pad drilling may result in volatility in our operating results.
- The unavailability or high cost of drilling rigs, completion equipment and services, supplies and personnel could adversely affect our ability to establish and execute exploration and development plans within budget and on a timely basis.
- We may be unable to acquire adequate supplies of water for our drilling and hydraulic fracturing operations or dispose of the water we use at a reasonable cost and pursuant to applicable environmental rules.

- Midstream projects are subject to risks of construction delays and cost over-runs.
- Our identified drilling locations are scheduled over several years, making them susceptible to uncertainties and lease expirations that could materially alter the occurrence or timing of their drilling.
- The seismic data and other technologies we use cannot eliminate exploration risk.

Risks Related to Third Parties

- Financial difficulties encountered by purchasers, operators or other third parties could decrease our cash flows from operations and adversely affect the exploration and development of our prospects and assets.
- The marketability of our production is dependent upon gathering, processing and transportation facilities.
- We conduct a portion of our operations through joint ventures, including San Mateo, which subjects us to certain risks.
- San Mateo's long-term success depends on its ability to obtain new sources of products, which depends on certain factors beyond its control.
- Certain of our long-term contracts require us to pay fees to our service providers based on minimum volumes regardless of actual volume throughput and may limit our ability to use other service providers.
- We do not own all of the land on which our midstream assets are located, which could disrupt our operations.
- Competition in our industry is intense, and our competitors may use superior technology and data resources.
- Strategic relationships upon which we may rely are subject to change.
- We have limited control over activities on properties we do not operate.

Risks Related to Laws and Regulations

- Approximately 33% of our leasehold and mineral acres in the Delaware Basin is located on federal lands, which are subject to various requirements and regulations.
- We are subject to government regulation, including complex environmental laws, which could require significant expenditures.
- We are subject to tax laws and may become subject to new taxes, or tax deductions currently available to us may be eliminated or reduced.
- Legislation and regulatory initiatives relating to hydraulic fracturing, induced seismicity, emissions and climate change could result in increased costs and additional operating restrictions or delays, and the physical effects of climate change could disrupt our production and cause us to incur significant costs.
- New climate disclosure rules proposed by the SEC or states in which we have operations or do business could increase our costs of compliance.
- We may incur significant costs and liabilities resulting from compliance with emissions or pipeline safety regulations.
- A change in the jurisdictional characterization of some of our assets by FERC or a change in policy by FERC may result in increased regulation of our assets.
- The rates of our regulated assets are subject to review and reporting by federal regulators.
- Should we fail to comply with FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.
- Derivatives legislation adopted by Congress could limit our ability to hedge risks associated with our business.
- Changes in U.S. foreign trade policies may materially and adversely affect our business, operations and financial condition.

Risks Related to Our Common Stock

- The price of our common stock has fluctuated substantially and may fluctuate substantially in the future.
- Attention to ESG and conservation matters and a negative shift in market perception towards the oil and natural gas industry could adversely affect us.
- Future sales and offerings of our common stock could depress the price of our common stock.
- Our directors and executive officers own a significant percentage of our equity, which could give them influence in corporate transactions and other matters, and their interests could differ from other shareholders.
- The issuance of preferred stock could diminish the rights of holders of our common stock.

General Risk Factors

- We may have difficulty managing growth in our business.
- The loss of any key personnel or Board member could disrupt our business operations.
- A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss.
- Our governing documents and Texas law may have anti-takeover effects that could prevent a change in control.
- We operate in a litigious environment and may be involved in legal proceedings.

Risks Related to our Financial Condition

Our success is dependent on the prices of oil, natural gas and NGLs. Low oil, natural gas and NGL prices and the continued volatility in these prices may adversely affect our financial condition and our ability to meet our capital expenditure requirements and financial obligations.

The prices we receive for the oil, natural gas and NGLs we produce heavily influence our revenue, profitability, cash flow available for capital expenditures, the repayment of debt, the payment of cash dividends, if any, the repurchase of our common stock, if any, access to capital, borrowing capacity under our Credit Agreement and future rate of growth. Oil, natural gas and NGLs are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and NGLs have been volatile and will likely continue to be volatile in the future. For the year ended December 31, 2025, oil prices averaged $64.73 per Bbl, as compared to $75.76 per Bbl in 2024, ranging from a high of $80.04 per Bbl in mid-January to a low of $55.27 per Bbl in mid-December, based upon the WTI oil futures contract price for the earliest delivery date. For the year ended December 31, 2025, natural gas prices averaged $3.62 per MMBtu, as compared to $2.40 per MMBtu in 2024, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. During 2025, natural gas prices ranged from a low of $2.70 per MMBtu in late August to a high of $5.29 per MMBtu in early December.

The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include the following:

- the domestic and foreign supply of, and demand for, oil, natural gas and NGLs;
- the actions of OPEC+ and state-controlled oil companies;
- the prices and availability of competitors' supplies of oil, natural gas and NGLs;
- the price and quantity of foreign imports and exports;
- the impact of U.S. dollar exchange rates;
- domestic and foreign governmental regulations and taxes;
- speculative trading of, and other financial market conditions affecting, oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering, processing and transportation systems for oil, natural gas and NGLs and gathering and disposal systems for produced water;
- the availability of refining capacity;
- the prices and availability of alternative fuel and energy sources;
- weather conditions and natural disasters, including floods, fires, tornadoes, droughts, hurricanes, tropical storms and severe cold weather;
- political conditions or conflicts in or affecting oil, natural gas and NGL producing regions or countries, including the United States, the Middle East, South America, Russia, Ukraine and China;
- the ongoing military conflicts between Russia and Ukraine and in the Middle East, as well as the related actions of U.S. and other governments and governmental organizations relating to oil, natural gas and NGLs, including through sanctions, embargoes, import restrictions and commodity price caps;
- the threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate oil, natural gas and NGL operations, including hydraulic fracturing, flaring, venting and produced water handling and disposal activities;
- the level of global oil, natural gas and NGL inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption;
- tariffs, trade restrictions and other supply chain constraints; and
- overall worldwide economic conditions.

These factors make it difficult to predict future commodity price movements with any certainty. Substantially all of our oil, natural gas and NGL sales are made in the spot market or pursuant to contracts based on spot market prices and are not

pursuant to long-term fixed price contracts. Further, oil, natural gas and NGL prices do not necessarily fluctuate in direct relation to each other.

Declines in oil, natural gas or NGL prices not only reduce our revenue, but could also reduce the amount of oil, natural gas and NGLs that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves and our ability to comply with the financial covenants under our Credit Agreement. Should oil, natural gas or NGL prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities or cease or delay further expansion of our midstream projects, each of which could have a material adverse effect on our business, financial condition, results of operations and reserves. In addition, such declines in commodity prices could cause a reduction in our borrowing base. If the borrowing base were to be less than the outstanding borrowings under our Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months.

Our industry and the broader U.S. economy have experienced higher than expected inflationary pressures in recent years. Should these conditions persist, it may impact our ability to procure services, materials and equipment on a cost-effective basis, or at all, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Although inflation in the U.S. softened in 2024 and 2025, prices for many services, materials and equipment have remained elevated relative to pre-2022 levels. Since 2022, we have experienced significant increases in the costs of certain oilfield services, materials and equipment, including diesel, steel, labor, trucking, sand, personnel and completion costs, among others. Supply and demand fundamentals have been aggravated by disruptions in global energy supply caused by multiple geopolitical events, including the ongoing military conflicts between Russia and Ukraine and in the Middle East, as well as related actions of the U.S. and other governments and governmental organizations relating to oil, natural gas and NGLs, including through sanctions, embargoes, import restrictions and commodity price caps. Should oil and natural gas prices increase, we expect to be subject to additional supply chain constraints and service cost inflation in future periods, which may increase our costs to drill, complete, equip and operate wells. In addition, supply chain disruptions and other inflationary pressures affecting the U.S. and global economy and the oil and natural gas industry may limit our ability to procure the necessary products and services we need for drilling, completing and producing wells in a timely and cost-effective manner, which could result in reduced margins and delays to our operations and could, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flows.

We cannot predict the impact of armed conflicts, including the ongoing military conflicts between Russia and Ukraine and in the Middle East, and the related humanitarian crises on the global economy, energy markets, geopolitical stability and our business.

Although our leasehold acreage is located primarily in the Delaware Basin, the occurrence or threat of terrorist attacks in the U.S. or any of the major energy producing regions of the world or elsewhere, anti-terrorist efforts and other armed conflicts involving the U.S. or other countries, including the conflicts between Russia and Ukraine and in the Middle East, which may include further sanctions, embargoes, export controls, supply chain disruptions, regional instability and geopolitical shifts, may have adverse effects on global macroeconomic conditions, increase volatility in the price and demand for oil and natural gas, increase exposure to cyberattacks (including cyberattacks targeting energy and pipeline infrastructure), cause disruptions in global supply chains, increase transportation and insurance costs, increase foreign currency fluctuations, cause constraints or disruption in the capital markets and limit sources of liquidity. Additionally, destructive forms of protest and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas activities could potentially result in personal injury to persons, damages to property, natural resources or the environment, or lead to extended interruptions of our or our customers' operations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and gas. Oil and gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our or our customers' operations is destroyed or damaged. Expenses related to security and costs for insurance may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all. We cannot predict the extent of these events' effects on our business and results of operations as well as on the global economy and energy markets.

Our exploration, development, exploitation and midstream projects require substantial capital expenditures that may exceed our cash flows from operations and potential borrowings, and we may be unable to obtain needed capital on satisfactory terms, which could adversely affect our future growth.

Our exploration, development, exploitation and midstream activities are capital intensive. Our cash, operating cash flows, contributions from our joint venture partners and potential future borrowings under our Credit Agreement, the San Mateo Credit

Facility or otherwise may not be sufficient to fund all of our future capital expenditures or future acquisitions. The rate of our future growth is dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

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

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce;
- the prices at which we sell our production and prevailing basis differentials;
- the costs of developing and producing our oil and natural gas reserves;
- the costs of constructing, operating and maintaining our midstream facilities;
- our ability to attract third-party customers for our midstream services;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks or other financial institutions to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, the possible occurrence of future events, such as decreases in the prices of oil and natural gas, or extended periods of such decreased prices, terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, failures of banks, general economic recessions, oil and natural gas industry recessions, oil and natural gas company bankruptcies, accounting scandals, overstated reserves estimates by public oil companies and disruptions in the financial and capital markets, has caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and spending and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

If our revenues decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or the value thereof or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in certain opportunities. Alternatively, to develop our properties, pay for higher service costs, fund acquisitions, increase our rate of growth, or expand our midstream operations, we may decide to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale or joint venture of midstream assets, oil and natural gas producing assets or leasehold interests, the sale or joint venture of oil and natural gas mineral interests, the borrowing of funds or otherwise to meet any increase in capital spending. If we succeed in selling additional equity securities or securities convertible into equity securities to raise funds or make acquisitions, the ownership of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through the issuance of new debt securities or additional indebtedness, we may become subject to additional covenants that restrict our business activities. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and results of operations could be adversely affected.

Our oil and natural gas reserves are estimated and may not reflect the actual volumes of oil and natural gas we will recover, and significant inaccuracies in these reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating accumulations of oil and natural gas is complex and inexact due to numerous inherent uncertainties. This process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of this technical data and the associated interpretations can vary. This process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions used.

The accuracy of any estimates of proved oil and natural gas reserves generally increases with the length of production history. Due to the limited production history of certain of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data becomes available, the estimated proved reserves will be

redetermined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance from our estimates could materially affect the quantities and present value of our reserves.

The calculated present value of future net revenues from our proved oil and natural gas reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

It should not be assumed that the present value of future net cash flows included in this Annual Report is the current market value of our estimated proved oil and natural gas reserves. As required by SEC rules and regulations, the estimated discounted future net cash flows from proved oil and natural gas reserves are based on current costs held constant over time without escalation and on commodity prices using an unweighted arithmetic average of first-day-of-the-month index prices, appropriately adjusted, for the 12-month period immediately preceding the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs used for these estimates and will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual costs and timing of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under GAAP is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

Approximately 39% of our total proved reserves at December 31, 2025 consisted of undeveloped and developed non-producing reserves, and those reserves may not ultimately be developed or produced.

At December 31, 2025, approximately 39% of our total proved reserves were undeveloped and less than 1% of our total proved reserves were developed non-producing. Our undeveloped and/or developed non-producing reserves may never be developed or produced, or such reserves may not be developed or produced within the time periods we have projected or at the costs we have estimated. SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they are related to wells scheduled to be drilled within five years after the date of booking. Delays in the development of our reserves or increases in costs to drill and develop such reserves would reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, resulting in some projects becoming uneconomical and reducing our total proved reserves. In addition, delays in the development of reserves or declines in the oil and/or natural gas prices used to estimate proved reserves in the future could cause us to have to reclassify a portion of our proved reserves as unproved reserves. Any reduction in our proved reserves caused by the reclassification of undeveloped or developed non-producing reserves could materially affect our business, financial condition, results of operations and cash flows.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

The rate of production from our oil and natural gas properties declines as our reserves are depleted. Our future oil and natural gas reserves and production and, therefore, our income and cash flow are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional oil and natural gas producing properties. We are currently focusing on developing our assets in the Delaware Basin, an area with intense competition and industry activity. As a result of this activity, we may have difficulty growing our current production, acquiring new properties or securing necessary services and labor in this area and may experience such difficulty in other areas in the future. During periods of low oil and/or natural gas prices, existing reserves may no longer be economic, and it will become more difficult to raise the capital necessary to finance expansion activities. If we are unable to replace our current and future production, our reserves will decrease, and our business, financial condition, results of operations and cash flows would be adversely affected.

We may be required to write down the carrying value of our proved properties under accounting rules, and these write-downs could adversely affect our financial condition.

There is a risk that we will be required to write down the carrying value of our oil and natural gas properties when oil or natural gas prices are low or are declining, as occurred in 2020. In addition, non-cash write-downs may occur if we have:

- downward adjustments to our estimated proved reserves;
- increases in our estimates of development costs; or

- deterioration in our exploration and development results.

We periodically review the carrying value of our oil and natural gas properties under full-cost accounting rules. Under these rules, the net capitalized costs of oil and natural gas properties less related deferred income taxes may not exceed a cost center ceiling that is calculated by determining the present value, based on constant prices and costs projected forward from a single point in time, of estimated future after-tax net cash flows from proved reserves, discounted at 10%. If the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceed the cost center ceiling, we must charge the amount of this excess to operations in the period in which the excess occurs. We may not reverse write-downs even if prices increase in subsequent periods. A write-down does not affect net cash flows from operating activities, liquidity or capital resources, but it does reduce the book value of our net tangible assets, retained earnings and shareholders' equity, and could lower the value of our common stock.

Hedging transactions, or the lack thereof, may limit our potential gains and could result in financial losses.

To manage our exposure to price risk, including price differential risk, we, from time to time, enter into hedging arrangements, using primarily "costless collars" or "swaps" with respect to a portion of our future production. Costless collars provide us with downside price protection through the purchase of a put option, which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. Three-way costless collars also provide us with downside price protection through the purchase of a put option, but they also allow us to participate in price upside through the purchase of a call option. The purchase of both the put option and call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially "costless" to us. In the case of a costless collar, the put option and the call option or options have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over the specified period, providing downside price protection. The goal of these and other hedges is to lock in a range of prices in the case of collars or a fixed price in the case of swaps so as to mitigate price volatility and increase the predictability of cash flows. These transactions limit our potential gains if oil, natural gas or NGL prices rise above the maximum price established by the call option or swap, as applicable, and may offer protection if prices fall below the minimum price established by the put option or swap, as applicable, only to the extent of the volumes then hedged.

In addition, hedging transactions may expose us to the risk of financial loss in certain other circumstances, including instances in which our production is less than expected or the counterparties to our put and call option or swap contracts fail to perform under the contracts. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the contracts. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when we have not hedged our production when, in retrospect, it would have been advisable to do so. Decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and NGL prices, and we may not always employ the optimal hedging strategy. We may employ hedging strategies in the future that differ from those that we have used in the past, and neither the continued application of our current strategies nor our use of different hedging strategies may be successful. See Note 12 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2025.

A change in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could adversely affect our business, financial condition, results of operations and cash flows.

The prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the WTI oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition, results of operations and cash flows.

Over the past several years, these oil and natural gas basis differentials were volatile and widened at various times. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—General Outlook and Trends" for additional information regarding the differentials. These wider oil and natural gas basis differentials were largely attributable to industry concerns regarding the near-term sufficiency of pipeline takeaway capacity for oil, natural gas and NGL production in the Delaware Basin. If we do experience any interruptions with takeaway capacity or NGL fractionation, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected.

Although the completion of additional oil and natural gas pipeline capacity from West Texas to the Texas Gulf Coast and other end markets improved these price differentials in the latter part of 2024 and early in 2025, these price differentials for natural gas remain wide and could widen further in future periods. Should we experience future periods of negative pricing for

natural gas as we have experienced historically, including in 2024 and 2025, we may again temporarily shut in certain high gas-oil ratio wells and take other actions to mitigate the impact on our realized natural gas prices and results.

A component of our growth has come, and may continue to come, through acquisitions, and our failure to identify, complete or integrate future acquisitions successfully could reduce our earnings and hamper our growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The pursuit and completion of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations and financial and management information systems and to attract, retain, motivate and effectively manage our employees. In addition, if we are not successful in identifying and acquiring properties, our earnings could be reduced and our growth could be restricted.

In addition, the success of our acquisitions will depend, in part, on our ability to realize the anticipated benefits and cost savings from integrating the acquired assets and operations into our business, and there can be no assurance that we will be able to successfully integrate or otherwise realize the anticipated benefits of our acquisitions. The inability to manage the integration of acquisitions effectively could reduce our focus on subsequent acquisitions and current operations and could negatively impact our results of operations and growth potential. Members of our management team may be required to devote considerable amounts of time to the integration process, which will decrease the time they will have to manage our business. Difficulties in integrating our acquisitions into our company may result in us performing differently than expected, in operational challenges or in the delay or failure to realize anticipated expense-related efficiencies, and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate our acquisitions operationally, in a manner that permits us to achieve the full revenue, expected cash flows and cost savings anticipated from such acquisitions;
- not realizing anticipated operating synergies; and
- potential environmental issues, unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with such acquisitions.

Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas and may require additional investments in personnel and infrastructure. Our financial condition, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods.

We may engage in bidding and negotiation to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the borrowing of funds, the issuance of debt or equity securities, the sale of production payments, the sale or joint venture of midstream assets or oil and natural gas producing assets or acreage or otherwise. Our Credit Agreement, the San Mateo Credit Facility and the indentures governing our outstanding senior notes include covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests.

We may purchase oil and natural gas properties or midstream assets with liabilities or risks that we did not know about or that we did not assess correctly, and, as a result, we could be subject to liabilities that could adversely affect our results of operations.

Before acquiring oil and natural gas properties or midstream assets, we assess the potential reserves, future oil and natural gas prices, operating costs, potential environmental liabilities, condition of the assets, customer contracts and other factors relating to the properties or assets, as applicable. However, our review process is complex and involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties or assets we buy. We may not become sufficiently familiar with the properties or assets to assess fully their deficiencies and capabilities. We may not perform inspections on every well, property or asset, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. Even when problems with a property or asset are identified, the seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other risks and liabilities in connection with properties or assets we acquire. If we acquire properties or assets with risks or liabilities we did not know about or that we did not assess correctly, our financial condition, results of operations and cash flows could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

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

If an examination of the title history of a property that we have purchased reveals oil and natural gas leases or mineral interests were purchased in error from a person who is not the owner of such interests or if the property has other title deficiencies, our interest would likely be worth less than what we paid or may be worthless. In such an instance, all or part of the amount paid for such oil and natural gas lease or mineral interest, as well as all or part of any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect, would be lost.

It is not our practice in all acquisitions of oil and natural gas leases or mineral interests, or undivided interests in such interests, to undergo the expense of retaining lawyers to examine the title to the interest. Rather, in certain acquisitions we rely upon the judgment of oil and natural gas brokers and landmen who perform the field work by examining records in the appropriate governmental office before attempting to acquire a lease or mineral interest.

Prior to the drilling of an oil and natural gas well, however, it is standard industry practice for the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such title review and curative work entails expense, which may be significant and difficult to accurately predict. A failure to cure any title defects may delay or prevent us from utilizing the associated leasehold right or mineral interest, which may adversely impact our ability to increase production and reserves. In the future, we may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights or mineral interests in properties in which we hold an interest, we will suffer a financial loss that could adversely affect our financial condition, results of operations and cash flows.

Our ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond our control, and in certain cases we may be required to retain liabilities for certain matters.

From time to time, we may sell a portion of an interest in a strategic asset for the purpose of assisting or accelerating the asset's development. In addition, we regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of such interests or nonstrategic assets or complete announced dispositions, including the receipt of approvals of governmental agencies or third parties and the identification of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and at prices acceptable to us.

Sellers typically retain certain liabilities or indemnify buyers for certain pre-closing matters, such as matters of litigation, environmental contingencies, royalty obligations and income taxes. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Risks Related to our Liquidity

We may not be able to generate sufficient cash to fund our capital expenditures, service all of our indebtedness and pay dividends to our shareholders, and we may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations 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 us to pay the principal, premium, if any, and interest on our 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, cease the payment of any dividends to our shareholders, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets, the syndicated bank market and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of 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 our 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. Our Credit Agreement, the San Mateo Credit Facility and the indentures governing our outstanding senior notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We 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 us to meet scheduled debt service obligations, which could have a material adverse effect on our financial condition and results of operations.

We may incur additional indebtedness, which could reduce our financial flexibility, increase interest expense and adversely impact our operations and our unit costs.

As of February 24, 2026, the maximum facility amount under the Credit Agreement was $3.50 billion, the borrowing base was $3.25 billion and our elected borrowing commitment was $2.25 billion. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected borrowing commitment (subject to compliance with the covenants noted below). As of February 24, 2026, we had available borrowing capacity of approximately $1.88 billion under our Credit Agreement (after giving effect to outstanding letters of credit and subject to our compliance with the covenants noted below).

As of February 24, 2026, the facility amount under the San Mateo Credit Facility was $1.10 billion, and San Mateo had available borrowing capacity of approximately $296.6 million (after giving effect to outstanding letters of credit and subject to San Mateo's compliance with the covenants noted below). The San Mateo Credit Facility includes an accordion feature, which provides for potential increases in the commitments of the lenders to up to $1.35 billion.

In the future, subject to the restrictions in the indentures governing our outstanding senior notes and in other instruments governing our other outstanding indebtedness (including our Credit Agreement and the San Mateo Credit Facility), we may incur significant amounts of additional indebtedness, including under our Credit Agreement and the San Mateo Credit Facility, through the issuance of additional notes or otherwise, in order to develop our properties, fund acquisitions or invest in certain opportunities. Interest rates on such future indebtedness may be higher than current levels, causing our financing costs to increase accordingly.

A high level of indebtedness could affect our operations in several ways, including:

- requiring a significant portion of our cash flows to be used for servicing our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our level of indebtedness may prevent us from pursuing;
- restricting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes; and
- increasing the risk that we may default on our debt obligations.

The borrowing base under our Credit Agreement is subject to periodic redetermination.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. We and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates. In addition, our lenders have the flexibility to reduce our borrowing base due to a variety of factors, some of which may be beyond our control. Since the borrowing base is subject to periodic redeterminations, if a redetermination resulted in a borrowing base that was less than our borrowings under the Credit Agreement, we could be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months. If we are required to do so, we may not have sufficient funds to fully make such repayments, which could result in a default under the terms of the Credit Agreement and an acceleration of the loans thereunder, requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

We are subject to interest rate risk under our Credit Agreement and the San Mateo Credit Facility.

Our earnings are exposed to interest rate risk associated with borrowings under our Credit Agreement and the San Mateo Credit Facility. Borrowings under the Credit Agreement may be in the form of a base rate loan or a loan based on the secured overnight financing rate administered by the Federal Reserve Bank of New York ("SOFR"). If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Overnight Bank Funding Rate (as defined in the Credit Agreement) on such day, plus 0.50%, and (iii) the Daily Simple SOFR (as defined in the Credit Agreement) on such day, plus 1.00%, plus, in each case, an amount ranging from 0.75% to 1.75% depending on the level of borrowings under the Credit Agreement. If we borrow funds as a SOFR loan, such borrowings will bear interest at a rate equal to (x) Term SOFR (as defined in the Credit Agreement) for the chosen interest period plus (y) an amount ranging from 1.75% to 2.75% depending on the level of borrowings under the Credit Agreement. If we have outstanding borrowings under

our Credit Agreement and interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Similarly, borrowings under the San Mateo Credit Facility may be in the form of a base rate loan or a SOFR loan. If San Mateo borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the San Mateo Credit Facility) on such day, plus 0.50% and (iii) Term SOFR (as defined in the San Mateo Credit Facility) for a one month tenor, plus 1.00% plus, in each case, an amount ranging from 1.00% to 2.00% depending on San Mateo's Consolidated Total Leverage Ratio (as defined in the San Mateo Credit Facility). If San Mateo borrows funds as a SOFR loan, such borrowings will bear interest at a rate equal to (x) Term SOFR for the chosen interest period plus (y) an amount ranging from 2.00% to 3.00% depending on San Mateo's Consolidated Total Leverage Ratio. The applicable margin for base rate loans and SOFR loans under the San Mateo Credit Facility will be decreased by 0.25% in the event of a Notes Offering (as defined in the San Mateo Credit Facility) or a Qualified IPO (as defined in the San Mateo Credit Facility). If San Mateo has outstanding borrowings under the San Mateo Credit Facility and interest rates increase, so will San Mateo's interest costs, which may have a material adverse effect on San Mateo's results of operations and financial condition.

Our Credit Agreement and the San Mateo Credit Facility have floating rates tied to SOFR or other interest rate benchmarks that generally increase or decrease alongside changes in the federal funds rates. As a result, interest expense on our existing floating rate debt rose during 2022 and 2023 as the Federal Reserve increased interest rates, and our interest expense remained high during 2024. In 2025, the Federal Reserve lowered interest rates three times, resulting in decreased interest expense on our existing floating rate debt in 2025. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

The terms of the agreements governing our outstanding indebtedness may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our Credit Agreement, the San Mateo Credit Facility and the indentures governing our senior notes contain, and any future indebtedness we or San Mateo incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our and San Mateo's ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that restrict our or San Mateo's ability to, among other things:

- incur or guarantee additional debt or issue certain types of preferred stock;
- declare or pay dividends or distributions or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments, loans and acquisitions;
- create or incur certain liens;
- change the nature of our business;
- become subject to FERC regulatory authority;
- enter into agreements that restrict dividends or other payments from our Restricted Subsidiaries (as defined in the indentures governing our outstanding senior notes) to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- enter into certain hedging agreements; and
- create unrestricted subsidiaries.

A breach of any of these covenants could result in an event of default under our Credit Agreement, the San Mateo Credit Facility and the indentures governing our outstanding senior notes. For example, our Credit Agreement requires us to comply with certain financial covenants, including maintaining a specified debt to EBITDA ratio and current ratio. Low oil and natural gas prices or a decline in our oil or natural gas production may adversely impact our EBITDA, cash flows and debt levels, and therefore our ability to comply with these covenants.

Similarly, the San Mateo Credit Facility requires San Mateo to comply with certain financial covenants, including maintaining a specified debt to EBITDA ratio and interest coverage ratio. Lower revenues as a result of less volumes than anticipated, or otherwise, or an increase in interest rates may adversely impact San Mateo's EBITDA and interest expense, and therefore San Mateo's ability to comply with these covenants. For a summary of these financial restrictions and other covenants

in our Credit Agreement, the San Mateo Credit Facility and the indentures governing our senior notes, see Note 7 to the consolidated financial statements in this Annual Report.

In addition, a change in control (as defined in the Credit Agreement, the San Mateo Credit Facility and the indentures governing our senior notes) could result in an event of default or prepayment event under the applicable debt instrument, which could have an adverse effect on our business by limiting our ability to take advantage of financing, merger and acquisition, or other opportunities.

Upon the occurrence of an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable, all applicable commitments to extend further credit could be terminated and the lenders under such debt agreements could seek to foreclose on any liens securing such debt. If indebtedness under our Credit Agreement, the San Mateo Credit Facility or the indentures governing our outstanding senior notes is accelerated, there can be no assurance that we will have sufficient assets to repay such indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future debt agreements could materially adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Our credit rating may be downgraded, which could reduce our financial flexibility, increase interest expense and adversely impact our operations.

As of February 24, 2026, our corporate credit ratings from S&P Global Ratings, Moody's Investors Service and Fitch Ratings were "BB-," "Ba3" and "BB," respectively. We cannot guarantee you that our credit 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. For example, in March 2020, our corporate credit ratings from S&P Global Ratings and Moody's Investors Services were downgraded in connection with a sudden decline in oil prices in early 2020, although those ratings were subsequently upgraded. Any future downgrade could increase the cost of any indebtedness incurred in the future.

Any increase in our financing costs resulting from a credit rating downgrade could adversely affect our ability to obtain additional financing in the future for working capital, capital expenditures, additional letters of credit or other credit support we may be required to provide to counterparties, acquisitions and general corporate or other purposes. If a credit rating downgrade were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations could be materially adversely affected.

The payment of dividends and the repurchase of shares of our common stock will be at the discretion of our Board of Directors and subject to numerous factors.

In each of the first, second and third quarters of 2025, our Board declared quarterly cash dividends of $0.3125 per share of common stock. In October 2025, the Board amended our dividend policy to increase the quarterly dividend to $0.375 per share of common stock and also declared a quarterly cash dividend of $0.375 per share of common stock. In February 2026, the Board declared a quarterly cash dividend of $0.375 per share of common stock payable on March 10, 2026 to shareholders of record as of February 27, 2026. We intend to continue to pay a quarterly dividend in the future pursuant to the dividend policy adopted by our Board. However, the payment and amount of future dividend payments, if any, are subject to declaration by our Board. Such payments will depend on, among other things, our available cash, earnings, financial condition, capital requirements, level of indebtedness, stock price, statutory and contractual restrictions applicable to the payment of dividends and other considerations that our Board deems relevant. Cash dividend payments in the future may only be made out of legally available funds, and, if we experience substantial losses, such funds may not be available.

In April 2025, the Board approved the Share Repurchase Program authorizing the repurchase of up to $400.0 million of common stock. However, the timing and number of shares that we may repurchase under the Share Repurchase Program is subject to a variety of factors, including our stock price, market conditions, trading volume and other uses for our free cash flow. There can be no assurance regarding the exact number of shares to be repurchased by us, if any. Depending on market conditions and other factors, these repurchases may be commenced or suspended at any time or periodically without prior notice, and the Share Repurchase Program does not obligate us to acquire any amount of common stock.

In addition, certain covenants in our Credit Agreement and the indentures governing our outstanding senior notes may limit our ability to pay dividends or repurchase shares of our common stock. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment, and there is no guarantee that the price of our common stock will exceed the price you paid. We are under no obligation to make dividend payments on, or repurchase shares of, our common stock and may cease such payments or repurchases at any time in the future. Any elimination of or downward revision in our dividend payout or Share Repurchase Program could have a material adverse effect on our stock price.

Risks Related to our Operations

Drilling for and producing oil, natural gas and NGLs is highly speculative and involves a high degree of operational and financial risk, with many uncertainties that could adversely affect our business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation and approvals before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells may be exceeded and such costs can increase significantly due to various complications that may arise during drilling, completion and operation. Before a well is spud, we may incur significant geological, geophysical and land costs, including seismic acquisition costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Exploration wells could bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill or participate in wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to affirmatively determine in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling and completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from, or abandonment of, the well. The productivity and profitability of a well may be negatively affected by a number of additional factors, including:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- limited access to electrical power sources or other infrastructure used in our operations;
- potential drainage of oil and natural gas from our properties by operations on adjacent properties;
- the existence or magnitude of faults or unanticipated geological features;
- loss of or damage to oilfield development and service tools;
- accidents, equipment failures or mechanical problems;
- title defects of the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut in;
- inflation in exploration, drilling, completion and production costs;
- domestic and foreign governmental regulations; and
- proximity to and capacity of gathering, processing, transportation and disposal facilities.

Furthermore, our exploration and production operations involve using some of the latest drilling and completion techniques developed by us, other operators and service providers. Risks that we face while drilling and completing horizontal wells include:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore;
- fracture stimulating the planned number of stages;
- drilling out the plugs between stages following hydraulic fracturing operations; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Each of these risks is magnified in wells with longer laterals. In 2025, the average completed lateral length for operated wells turned to sales was approximately 10,400 feet. If we do not drill productive and profitable wells in the future, our business, financial condition, results of operations, cash flows and reserves could be materially and adversely affected.

Our operations are subject to operational hazards and risks, which could result in significant damages and the loss of revenue.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production, gathering, transportation and processing, including:

- natural disasters;
- adverse weather conditions, including floods, fires, tornadoes, droughts, hurricanes, tropical storms and severe cold weather;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- damage to pipelines, processing plants and disposal wells and associated facilities;
- fires or explosions;
- releases of hazardous substances, toxic gases such as hydrogen sulfide or other waste materials;
- pressures or irregularities in formations; and
- equipment failures or accidents.

In addition, there is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations and services, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Any of these or other similar occurrences could result in the disruption or impairment of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Furthermore, our operations may be subject to curtailment due to seismic events. In 2021, the NMOCD established a statewide induced seismicity mitigation and response framework in response to seismic events in New Mexico. These protocols require enhanced reporting and varying levels of curtailment of injection rates for salt water disposal wells, including potentially shutting in wells, in the area of seismic events based on the magnitude, timing and proximity to the seismic event. If a seismic event were to occur in the area of our operations, the salt water disposal wells that we deliver to or operate may be shut in or curtailed, which may result in increased expenses or the curtailment of our oil and natural gas production. In addition, if such a seismic event occurred in the area of the Company's or San Mateo's operations, the Company or San Mateo may be required to shut in or curtail the volumes disposed in its salt water disposal wells. Previous seismic events have required the Company and San Mateo to curtail injection volumes and have increased reporting requirements for affected salt water disposal wells. Any such further events could adversely impact our and San Mateo's revenues and cash flows.

There are also significant risks associated with the operation of cryogenic natural gas processing plants such as the Marlan Processing Plant and the Black River Processing Plant. Natural gas and NGLs are volatile and explosive and may include carcinogens. Damage to or improper operation of the Black River Processing Plant or the Marlan Processing Plant could result in an explosion or the discharge of toxic gases, which could result in significant damage claims, interrupt a revenue source and prevent us from processing some or all of the natural gas produced from our wells or third-party wells located in nearby asset areas. Furthermore, if we were unable to process such natural gas, we may be forced to flare natural gas from, or shut in, the affected wells for an indefinite period of time.

In addition, San Mateo's gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within our control. These pipelines, plants, salt water disposal wells and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if San Mateo's costs to access and transport on these third-party pipelines significantly increase, its profitability could be reduced. If

any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport, process or dispose of product, or if the volumes San Mateo gathers, processes or transports do not meet the product quality requirements of such pipelines or facilities, our and San Mateo's revenues and cash flows could be adversely affected.

Insurance against all operational risks is not available to us.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. Pollution and environmental risks generally are not fully insurable. In addition, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable prices or on commercially reasonable terms. Changes in the insurance markets due to various factors may make it more difficult for us to obtain certain types of coverage in the future. As a result, we may not be able to obtain the levels or types of insurance we would have otherwise obtained prior to these market changes, and the insurance coverage we do obtain may not cover certain hazards or all potential losses that are currently covered, and may be subject to large deductibles. Additionally, the proceeds of any such insurance may not be received in a timely manner. Losses and liabilities from uninsured and underinsured events and delays in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because our reserves and production are concentrated in a few core areas, problems with production in and markets for a particular area could have a material impact on our business.

Almost all of our current oil and natural gas production and our proved reserves are attributable to our properties in the Delaware Basin in Southeast New Mexico and West Texas and the Haynesville shale in Northwest Louisiana. In recent years, the Delaware Basin has become an area of increasing focus for us, and approximately 98% of our total oil and natural gas production for 2025 was attributable to our properties in the Delaware Basin. Since 2016, the vast majority of our capital expenditures have been allocated to the Delaware Basin. We expect that substantially all of our capital expenditures in 2026 will continue to be in the Delaware Basin, with the exception of amounts allocated to limited operations and certain non-operated well opportunities in our Haynesville shale position.

The industry focus on the Delaware Basin may adversely impact our ability to gather, transport and process our oil and natural gas production due to significant competition for access to gathering systems, pipelines, processing and refinery facilities and oil, condensate and produced water trucking operations. Due to the concentration of our operations, we may be disproportionately exposed to the impact of delays or interruptions of production from our wells in our operating areas caused by transportation capacity constraints or interruptions, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions or plant closures for scheduled or unscheduled maintenance. Due to our concentration of properties in the Delaware Basin, we are also particularly exposed to any differential between benchmark prices of oil and natural gas and the wellhead price we receive for our production. See "—Risks Related to our Financial Condition—A change in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could adversely affect our business, financial condition, results of operations and cash flows."

Our operations may also be adversely affected by weather conditions and events such as floods, fires, tornadoes, droughts, hurricanes, tropical storms and severe cold weather, resulting in delays in drilling and completions, damage to facilities and equipment and the inability to receive equipment or access personnel and products at affected job sites in a timely manner. For example, in recent years, the Delaware Basin has experienced periods of severe winter weather that impacted many operators. In particular, weather conditions and freezing temperatures have resulted in shut-ins of producing wells, power outages, curtailments in trucking, delays in drilling and completion of wells and other production constraints. Certain areas of the Delaware Basin have also experienced periods of severe flooding that impacted our operations as well as many other operators in the area, resulting in delays in drilling, completing and initiating production on certain wells. As we continue to focus our operations on the Delaware Basin, we may increasingly face these and other challenges posed by severe weather.

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. For example, our operations in the Delaware Basin are subject to particular restrictions on drilling activities based on environmental sensitivities and requirements and potash mining operations. Such delays, interruptions or restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our rate of return, cash flow from operations and shareholder value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our rate of return, cash flow from operations and shareholder value. Due to many factors, however, including some beyond our control, there is no guarantee that we will be able to find the optimal plan. Future drilling and completion efforts may impact production from existing wells, and parent-child well effects may impact future well productivity as a result of timing, spacing proximity or other factors. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our financial condition, results of operations and cash flows.

Certain 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.

Certain 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.

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 produced until other wells being drilled on the pad at the same time are drilled and completed, multi-well pad drilling delays the commencement of production from wells drilled on a given pad, which may cause volatility in our operating results. In addition, problems affecting one well could adversely affect production from other wells on the same pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production. Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

The unavailability or high cost of drilling rigs, completion equipment and services, supplies and personnel, including hydraulic fracturing equipment and personnel, could adversely affect our ability to establish and execute exploration and development plans within budget and on a timely basis, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Shortages or the high cost of drilling rigs, completion equipment and services, drill pipe, casing and other tubular goods, personnel or supplies, including sand and other proppants, could delay or adversely affect our operations. When drilling activity in the United States or a particular operating area increases, associated costs typically also increase, including those costs related to drilling rigs, equipment, supplies, drill pipe, casing and other tubular goods, including sand and other proppants, and personnel and the services and products of other industry vendors. These costs may increase, and necessary equipment, supplies and services may become unavailable to us at economical prices. Should this increase in costs occur, we may delay drilling or completion activities, which may limit our ability to establish and replace reserves, or we may incur these higher costs, which may negatively affect our business, financial condition, results of operations and cash flows. In addition, should oil and natural gas prices decline, third-party service providers may face financial difficulties and be unable to provide services. A reduction in the number of service providers available to us may negatively impact our ability to retain qualified service providers, or obtain such services at costs acceptable to us. Further, supply chain disruptions, tariffs and trade restrictions and other inflationary pressures affecting the United States and global economy and the oil and natural gas industry may limit our ability to procure the necessary products and services for drilling and completing wells in a timely and cost effective manner, which could result in reduced margins and delays in our drilling and completion activities which, in turn, could adversely affect our business, financial condition, results of operations and cash flows.

In addition, the demand for hydraulic fracturing services from time to time exceeds the availability of fracturing equipment and crews across the industry and in certain operating areas in particular. The accelerated wear and tear of hydraulic fracturing equipment due to its deployment in unconventional oil and natural gas fields characterized by longer lateral lengths and larger numbers of fracturing stages could further amplify such an equipment and crew shortage. If demand for fracturing services were to increase or the supply of fracturing equipment and crews were to decrease, higher costs or delays in procuring these services could result, which could adversely affect our business, financial condition, results of operations and cash flows.

If we are unable to acquire adequate supplies of water for our drilling and hydraulic fracturing operations or are unable to dispose of the water we use at a reasonable cost and pursuant to applicable environmental rules, our ability to produce oil and natural gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our drilling and hydraulic fracturing operations. Our inability to obtain sufficient amounts of water at reasonable prices, or treat and dispose of water after drilling and hydraulic fracturing, could adversely impact our operations. In recent years, Southeast New Mexico and West Texas have experienced severe drought. As a result, we may experience difficulty in securing the necessary volumes of water for our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as (i) hydraulic fracturing, including the use of fresh water in such operations, or (ii) disposal of waste, including the disposal of produced water, drilling fluids and other wastes associated with the exploration, development and production of oil and natural gas. Furthermore, future environmental regulations and permitting requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, and all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Construction of midstream projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity.

From time to time, we, through San Mateo or otherwise, plan and construct midstream projects, some of which may take a number of months before commercial operation, such as construction of oil, natural gas and produced water gathering or transportation systems, construction of natural gas processing plants, drilling of commercial salt water disposal wells and construction of related facilities. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, government and regulatory approval, compliance with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our business, results of operations, liquidity, financial condition and the ability of San Mateo to attract third-party customers. The construction of produced water disposal facilities, pipelines and gathering and processing facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Additionally, financing for these development projects may not be available on economically acceptable terms or at all. Should the actual costs of these projects exceed our estimates, our liquidity and financial condition could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

Moreover, our revenues may not increase immediately, or at all, upon the expenditure of funds on a particular project. For instance, if we or San Mateo build additional gathering assets, the construction may occur over an extended period of time and we may not receive any material increases in revenues until the project is completed or at all. We or San Mateo may construct facilities to capture anticipated future production growth from our customers in an area where such growth does not materialize. As a result, new midstream assets may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our financial condition and results of operations.

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

Our management team has identified and scheduled drilling locations in our operating areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including oil and natural gas prices, assessment of risks, costs, drilling results, reservoir heterogeneities, the availability of equipment and capital, approval by regulators, lease terms, seasonal conditions and the actions of other operators. Additionally, as lateral lengths greater than one mile have become increasingly common in the Delaware Basin, we may have to cooperate with other operators to ensure that our acreage is included in drilling units or otherwise developed. The final determination on whether to drill any of the identified locations will be dependent upon the factors described elsewhere in this Annual Report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe, or at all, or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

Certain of our unproved and unevaluated acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

At December 31, 2025, we had leasehold interests in approximately 37,900 net acres across all of our areas of interest that are not currently held by production and are subject to leases with primary or renewed terms that expire prior to 2031. Unless we establish and maintain production, generally in paying quantities, on units containing these leases during their terms or we renew such leases, these leases will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases, or top leases, may have been taken and could become immediately effective if our leases expire. If our leases expire or we are unable to renew such leases, we will lose our right to develop the related properties. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

The 2-D and 3-D seismic data and other advanced technologies we use cannot eliminate exploration risk, which could limit our ability to replace and grow our reserves and materially and adversely affect our results of operations and cash flows.

We employ visualization and 2-D and 3-D seismic images to assist us in exploration and development activities where applicable. These techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses by drilling unproductive wells based on these technologies. Furthermore, the acquisition of seismic and geological data can be expensive and require the incurrence of various risks and liabilities, and we may not be able to license or obtain such data at an acceptable cost. Poor results from our exploration and development activities could limit our ability to replace and grow reserves and adversely affect our business, financial condition, results of operations and cash flows.

Risks Related to Third Parties

Financial difficulties encountered by our oil, natural gas and NGL purchasers, third-party operators, third-party customers or other third parties could decrease our cash flows from operations and adversely affect the exploration and development of our prospects and assets.

We derive most of our revenues from the sale of our oil, natural gas and NGLs to unaffiliated third-party purchasers, independent marketing companies and midstream companies. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For each of the years ended December 31, 2025, 2024 and 2023, we had three significant purchasers that collectively accounted for approximately 72%, 79% and 76%, respectively, of our total oil, natural gas and NGL revenues. We cannot ensure that we will continue to have ready access to suitable markets for our future production. If we lost one or more of these customers and were unable to sell our production to other customers on terms we consider acceptable, it could materially and adversely affect our business, financial condition, results of operations and cash flows. Furthermore, we cannot predict the extent to which counterparties' businesses would be impacted if oil and natural gas prices decline, such prices remain depressed for a sustained period of time or other conditions in our industry were to deteriorate. Any delays in payments from our purchasers caused by financial problems encountered by them could have an immediate negative effect on our results of operations and cash flows.

In addition to credit risk related to purchasers of our production, we also face credit risk through receivables from joint interest owners on properties we operate and from San Mateo's customers. Joint interest receivables arise from billing entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We are generally unable to control which co-owners participate in our wells. Liquidity and cash flow problems encountered by our joint interest owners or the third-party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our joint interest owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farmout party, we would have to find a new farmout party or obtain alternative funding in order to complete the exploration and development of the prospects subject to a farmout agreement. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs. If we are not able to obtain the capital necessary to fund either of these contingencies or find a new farmout party, our results of operations and cash flows could be adversely affected.

The marketability of our production is dependent upon oil, natural gas and NGL gathering, processing and transportation facilities, and the unavailability of satisfactory oil, natural gas and NGL gathering, processing and transportation arrangements could have a material adverse effect on our revenue.

The unavailability of satisfactory oil, natural gas and NGL gathering, processing and transportation arrangements may hinder our access to oil, natural gas and NGL markets or delay production from our wells. The availability of a ready market for our oil, natural gas and NGL production depends on a number of factors, including the demand for, and supply of, oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and oil and condensate

trucking operations. Such systems and operations include those of San Mateo, as well as other systems and operations owned and operated by third parties. The continuing operation of, and our continuing access to, third-party systems and operations is outside our control. Regardless of who operates the midstream systems or operations upon which we rely, our failure to obtain these services on acceptable terms could materially harm our business. In addition, certain of these gathering systems, pipelines and processing facilities, particularly in the Delaware Basin, may be outdated or in need of repair and subject to higher rates of line loss, failure and breakdown. Furthermore, such facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues.

We may be required to shut in wells for lack of a market or because of inadequate or unavailable pipelines, gathering systems, treating, compression or processing facilities or trucking capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases.

The disruption of our own or third-party facilities due to maintenance, weather or other factors could negatively impact our ability to market and deliver our oil, natural gas and NGLs. If our costs to access and transport on these pipelines significantly increase, our profitability could be reduced. Third parties control when or if their facilities are restored and what prices will be charged. In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production. While we have entered into natural gas processing, treating, compression and transportation agreements covering the anticipated natural gas production from a significant portion of our Delaware Basin acreage in Southeast New Mexico and West Texas, no assurance can be given that these agreements will alleviate these issues completely, and we may be required to pay deficiency payments under such agreements if we do not meet the gathering or processing commitments, as applicable. For example, in the fourth quarter of 2025, we experienced temporary oil and natural gas pipeline and processing interruptions due to maintenance and constraints that are estimated to have resulted in approximately 3,600 BOE per day of less production. We may experience similar interruptions and processing capacity constraints in the future as we continue to explore and develop our Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin. If we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We conduct a portion of our operations through joint ventures, which subjects us to additional risks that could have a material adverse effect on the success of these operations, our financial position, results of operations or cash flows.

We own and operate substantially all of our midstream assets in Eddy County, New Mexico and Loving County, Texas and a significant proportion of our midstream assets in Lea County, New Mexico through San Mateo, and we have and may continue to enter into other joint venture arrangements in the future. The nature of a joint venture requires us to share a portion of control with unaffiliated third parties. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may not control. In addition, if our joint venture partners do not fulfill their contractual, financial and other obligations, the affected joint venture may be unable to operate according to its business plan, and we may be required to increase our level of financial commitment or seek third-party capital, which could dilute our ownership in the applicable joint venture. If we do not timely meet our financial commitments or otherwise comply with our joint venture agreements, our ownership of and rights with respect to the applicable joint venture may be reduced or otherwise adversely affected. Furthermore, there can be no assurance that any joint venture will be successful or generate cash flows at the level we have anticipated, or at all. Differences in views among joint venture participants could also result in delays in business decisions or otherwise, failures to agree on major issues, operational inefficiencies and impasses, litigation or other issues. We provide management functions for certain joint ventures and may provide such services for future joint venture arrangements, which may require additional time and attention of management or require us to hire or contract additional personnel. Third parties may also seek to hold us liable for a joint venture's liabilities. These issues or any other difficulties that cause a joint venture to deviate from its original business plan could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because of the natural decline in production in the regions of San Mateo's midstream operations, San Mateo's long-term success depend on its ability to obtain new sources of products, which depends on certain factors beyond San Mateo's control. Any decrease in supplies to their midstream facilities could adversely affect San Mateo's business and operating results.

San Mateo's midstream facilities are, or will be, connected to oil and natural gas wells operated by us or by third parties from which production will naturally decline over time, which means that the cash flows associated with these sources of oil, natural gas, NGLs and produced water will also decline over time. Some of these third parties are not subject to minimum volume commitments. To maintain or increase throughput levels on San Mateo's gathering systems and the utilization rate at its other midstream facilities, San Mateo must continually obtain new sources of products. San Mateo's ability to obtain additional

sources of oil, natural gas, NGLs and produced water depends, in part, on the level of successful drilling and production activity near its gathering and transportation systems and other midstream facilities. San Mateo has no control over the level of activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, San Mateo has no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, the availability of drilling rigs, other production and development costs and the availability and cost of capital.

We have entered into certain long-term contracts that require us to pay fees to our service providers based on minimum volumes regardless of actual volume throughput and that may limit our ability to use other service providers.

From time to time, we have entered into and may in the future enter into certain oil, natural gas or produced water gathering, treating, compression or transportation agreements, natural gas processing agreements, NGL transportation agreements, produced water disposal agreements or similar commercial arrangements with midstream companies, including San Mateo and its subsidiaries. Certain of these agreements require us to meet minimum volume commitments, often regardless of actual throughput. Reductions in our drilling activity could result in insufficient production to fulfill our obligations under these agreements. As of December 31, 2025, our long-term contractual obligations under agreements with minimum volume commitments totaled approximately $3.06 billion over the terms of the agreements. If we have insufficient production to meet the minimum volume commitments under any of these agreements, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operations.

Pursuant to certain of our agreements with midstream companies, we have dedicated our current and future leasehold interests in certain of our asset areas to counterparties. As a result, we will be limited in our ability to use other gathering, processing, disposal and transportation service providers, including our midstream business, even if such service providers are able to offer us more favorable pricing or more efficient service.

We do not own all of the land on which our midstream assets are located, which could disrupt our operations.

We do not own all of the land on which our midstream assets are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs or royalties to retain necessary land access if we do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to construct and operate our midstream assets on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land or find alternative locations for our operations at increased costs, each of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas, provide midstream services and secure trained personnel, and our competitors may use superior technology and data resources that we may be unable to afford.

Competition is intense in virtually all facets of our business. Our ability to acquire additional prospects and to find and develop reserves in the future will depend in part on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, to market oil and natural gas and to secure trained personnel. Similarly, our midstream business, and particularly the success of San Mateo, depends in part on our ability to compete with other midstream service companies to attract third-party customers to our midstream facilities. San Mateo competes with other midstream companies that provide similar services in their areas of operations, and such companies may have legacy relationships with producers in those areas and may have a longer history of efficiency and reliability. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical, technological and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical, technological or personnel resources permit. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we use or that we may implement in the future may become obsolete, and our operations may be adversely affected.

In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased in recent years due to a competitive labor market, inflation and other factors, and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, developing midstream assets, marketing

hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Strategic relationships upon which we may rely are subject to change, which may diminish our ability to conduct our operations.

Our ability to explore, develop and produce oil and natural gas resources successfully, acquire oil and natural gas interests and acreage and conduct our midstream activities depends on our developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable acquisition opportunities in a highly competitive environment. These relationships are subject to change and, if they do, our ability to grow may be impaired.

To develop our business, we endeavor to use the business relationships of our management and Board to enter into strategic relationships, which may take the form of contractual arrangements with other oil and natural gas companies and service companies, including those that supply equipment and other resources that we expect to use in our business, as well as midstream companies and certain financial institutions. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to incur or undertake in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

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

We are not the operator on some of our properties in Northwest Louisiana, particularly in the Haynesville shale. We also have other non-operated acreage positions in Southeast New Mexico and West Texas. Because we are not the operator for these properties, our ability to exercise influence over the operations of these properties or their associated costs is limited. Our dependence on the operators and other working interest owners of these projects and our limited ability to influence operations and associated costs, or control the risks, could materially and adversely affect the drilling results, reserves and future cash flows from these properties. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the rate of production of reserves, if any;
- approval of other participants in drilling wells; and
- selection and implementation or execution of technology.

In areas where we do not have the right to propose the drilling of wells, we may have limited influence on when, how and at what pace our properties in those areas are developed. Further, the operators of those properties may experience financial problems in the future or may sell their rights to another operator not of our choosing, both of which could limit our ability to develop and monetize the underlying oil or natural gas reserves. In addition, the operators of these properties may elect to curtail the oil or natural gas production or to shut in the wells on these properties during periods of low oil or natural gas prices, and we may receive less than anticipated or no production and associated revenues from these properties until the operator elects to return them to production.

Risks Related to Laws and Regulations

Approximately 33% of our leasehold and mineral acres in the Delaware Basin is located on federal lands, which are subject to administrative permitting requirements and potential federal legislation, regulation and orders that may limit or restrict oil and natural gas operations on federal lands.

At December 31, 2025, Matador held approximately 212,500 net leasehold and mineral acres in the Delaware Basin, primarily in Eddy and Lea Counties, New Mexico and in Loving, Ward and Winkler Counties, Texas, of which approximately 70,900 net acres, or about 33%, was on federal lands administered by the BLM. In addition to permits issued by state and local authorities, oil and natural gas activities on federal lands also require permits from the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the permitting process for oil and natural gas activities not located on federal lands. In addition, government disruptions, such as a shutdown of the U.S. federal government resulting from the failure to pass budget appropriations, adopt continuing funding resolutions or raise the debt ceiling, could delay or halt the granting and renewal of such permits or other licenses, approvals or certificates required to conduct our operations. Delays in obtaining necessary permits or other approvals can disrupt our operations and have a material adverse effect on our business. BLM leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. These operations are also subject to BLM rules regarding engineering and construction specifications for

production facilities, ability to commingle production, safety procedures, the valuation of production, the payment of royalties, the removal of facilities, the posting of bonds, hydraulic fracturing, the control of air emissions and other areas of environmental protection. These rules could result in increased compliance costs for our operations, which in turn could have a material adverse effect on our business and results of operations. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. In addition, litigation related to leasing and permitting of federal lands could also restrict, delay or limit our ability to conduct operations on our federal leasehold or acquire additional federal leasehold. At the federal level, various policy makers, regulatory agencies and political candidates have also proposed restrictions on hydraulic fracturing, including its outright prohibition. It is possible that any such restrictions on hydraulic fracturing may particularly target activity on federal lands. Any federal legislation, regulations or orders intended to limit or restrict oil and natural gas operations on federal lands, if enacted, could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Oil and natural gas exploration and production activities on federal lands are also subject to NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. This process, including any additional requirements that may be implemented due to, or litigation regarding, the process, has the potential to delay or even halt development of future oil and natural gas projects subject to review under NEPA. See "Business—Regulation—Oil and Natural Gas Regulation."

We are subject to government regulation and liability, including complex environmental laws, which could require significant expenditures.

The exploration, development, production, gathering, processing, transportation and sale of oil and natural gas in the United States are subject to many federal, state and local laws, rules and regulations, including complex environmental laws and regulations. A change in the presidential administration, as well as a closely divided Congress, may also increase the uncertainty with regard to potential changes in these laws, rules and regulations and the enforcement of any new legislation or directives by governmental authorities. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation, gathering and transportation of oil, natural gas and NGLs, gathering and disposal of produced water, environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, we may be required to make large expenditures that could materially adversely affect our financial condition, results of operations and cash flows. If existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations or those of our service providers, such changes may affect the costs that we pay for such services or the results of business. In addition to expenditures required in order for us to comply with such laws and regulations, expenditures required by such laws and regulations could also include payments and fines for:

- personal injuries;
- property damage;
- containment and clean-up of oil, produced water and other spills;
- venting, flaring or other emissions;
- management and disposal of hazardous materials;
- remediation, clean-up costs and natural resource damages; and
- other environmental damages.

We do not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. The costs of remedying noncompliance may be significant, and remediation obligations could adversely affect our financial condition, results of operations and leasehold acreage. Laws, rules and regulations related to the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on us for environmental damage and disposal of hazardous and non-hazardous materials even if we were not negligent or at fault. We may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules or regulations at the time we performed those acts. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which our wells are drilled or our facilities are located, the owners of properties adjacent to or in close proximity to those properties or non-governmental organizations such as environmental groups, may also pursue legal actions against us based on alleged non-compliance with certain of these laws, rules and regulations. For example, a number of lawsuits have been filed in some states against others in our industry alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring

properties or otherwise violated state and federal rules regulating waste disposal. Private parties may also pursue legal actions challenging permitting programs that authorize certain of our operations.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production or midstream activities. Oil and natural gas operations in certain of our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect migratory birds or various threatened or endangered species. For example, our participation in candidate conservation agreements or the USFWS's designation of previously unprotected species as threatened or endangered species could prohibit drilling or other operations in certain of our operating areas, cause us to incur increased costs arising from species protection measures or result in limitations on our exploration and production and midstream activities, each of which could have a material adverse impact on our business, financial condition, results of operations and cash flows. See "Business—Regulation."

We are subject to federal, state and local taxes and may become subject to new taxes or have eliminated or reduced certain federal income tax deductions currently available with respect to oil and natural gas exploration and production activities as a result of future legislation, which could adversely affect our business, financial condition, results of operations and cash flows.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. For instance, in New Mexico, there have been proposals to impose a surtax on natural gas processors that, if enacted into law, could adversely affect the prices we receive for our natural gas processed in New Mexico.

Our federal and state income tax liabilities in 2026 and subsequent years will be dependent upon a variety of factors that will impact our taxable income, including oil and natural gas prices, allowable deductions and any legislative changes thereon, in addition to any tax credits generated that would offset tax liabilities in future periods.

Additionally, U.S. federal income tax law provides for a 15% corporate minimum income tax for certain corporations with more than $1 billion in average adjusted financial statement income for the three-year tax period ending before the corporation's current tax year. The impact of the 15% corporate minimum tax will depend on our results of operations each year. We do not expect such minimum tax to have any immediate material impact.

In addition, from time to time there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals at the U.S. federal level. Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such changes include (i) the repeal of the percentage depletion allowance for certain oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production or manufacturing activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. The passage of any such legislation or any other similar change in U.S. federal income or state tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production activities and could negatively impact our financial condition, results of operations and cash flows.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand or other proppants and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to complete wells in order to produce oil, natural gas and NGLs from formations where we focus our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Federal, state and local laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. In past sessions, Congress has considered, but has not passed, legislation to amend the SDWA, to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. Also at the federal level, in March 2015, the BLM issued final rules, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water, to regulate hydraulic fracturing on federal and Indian lands, but these rules never became effective. These rules were rescinded by rule in December 2017. The rescission was challenged, and the challenge remains pending before the Ninth Circuit Court of Appeals.

Various policymakers, regulatory agencies and political candidates at the federal, state and local levels have proposed restrictions on hydraulic fracturing, including its outright prohibition. Any such restrictions on hydraulic fracturing on federal lands could adversely impact our operations in the Delaware Basin, and an outright prohibition would adversely impact essentially all of our operations. In addition, a number of states and local regulatory authorities are considering or have

implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans or moratoria on drilling that effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations.

The adoption of new laws or regulations imposing reporting or operational obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or BLM, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

The potential adoption of federal, state and local legislation and regulations intended to address potential induced seismicity in the areas in which we operate could restrict our drilling and production activities and our midstream operations, as well as our ability to dispose of produced water gathered from such activities, which could decrease our and San Mateo's revenues and result in increased costs and additional operating restrictions or delays.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for produced water disposal and the increased occurrence of seismic activity. When caused by human activity, such events are called "induced seismicity." Regulatory agencies at all levels are continuing to study the possible link between oil and natural gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states against others in our industry alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states, including New Mexico and Texas, have imposed additional regulatory or permitting requirements, including requirements regarding the permitting of salt water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells and have modified their regulations or guidance to mitigate potential causes of induced seismicity. See "Business—Regulation—Underground Injection and Hydraulic Fracturing."

Increased seismicity in areas in which we operate could result in additional regulation and restrictions on the use of injection wells by us or by third parties whom we may contract with to dispose of produced water. Additional regulation and attention given to induced seismicity could also lead to greater opposition, including litigation, to oil and natural gas activities. Any one or more of these developments may result in operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. We and San Mateo dispose of large volumes of produced water gathered from our and third parties' drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in curtailment of injection operations, the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of produced water gathered from drilling and production activities could adversely impact our business, cash flows and results of operations and could decrease our and San Mateo's revenues and result in increased costs and additional operating restrictions or delays.

Legislation or regulations restricting emissions of greenhouse gases or promoting the development of alternative sources of energy could result in increased operating costs and reduced demand for the oil, natural gas and NGLs we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

We believe it is likely that scientific, public and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations and litigation that could affect our operations. Our operations result in greenhouse gas emissions. While the Trump administration has rolled back many regulations and findings related to greenhouse gas emissions and their effects on public health and welfare, a future administration may seek to impose new legislation or rules related to greenhouse gas emissions that could impact our operations. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. In addition, the United States has at times been a party to certain international agreements, pacts and other commitments designed to address climate change and reduce greenhouse gas emissions, including the Paris Agreement and the Glasgow Climate Pact. For further discussion of these international commitments, see "Business—Regulation—Environmental, Health and Safety Regulation."

On August 16, 2022, the IRA created the Methane Emissions Reduction Program to incentivize methane emission reductions and, for the first time ever, impose a waste emissions charge on greenhouse gas emissions from certain facilities that exceed specified emissions levels. However, the OBBBA delayed implementation of the waste emissions charges for the oil and gas industry until 2034. The EPA has begun adopting and implementing a suite of regulations to restrict greenhouse gas emissions under existing provisions of the CAA and the authority of the IRA. In addition, some states, including New Mexico,

have implemented rules and regulations relating to greenhouse gas emissions. For further discussion of these federal and state regulations, see "Business—Regulation—Environmental, Health and Safety Regulation."

In a 2010 interpretative guidance on climate change disclosures, the SEC indicated that climate change could have an effect on the severity of weather (including hurricanes, droughts, floods and freezes), sea levels, the arability of farmland and water availability and quality. If such effects were to occur, there is the potential for our exploration and production operations to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production, less efficient or non-routine operating practices necessitated by climate effects, impacts on our workforce, supply chain or distribution chain and increased costs for, or difficulty procuring consistent levels of, insurance coverage in the aftermath of such effects. Any future exploration and development activities and equipment could also be adversely affected by severe weather conditions, such as floods, fires, tornadoes, droughts, hurricanes, tropical storms or severe cold weather, which may cause a loss of production from temporary cessation of activity from regional power outages or lost or damaged facilities and equipment. Such severe weather conditions could also impact access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by us or other midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. See "—Risks Related to our Operations—If we are unable to acquire adequate supplies of water for our drilling and hydraulic fracturing operations or are unable to dispose of the water we use at a reasonable cost and pursuant to applicable environmental rules, our ability to produce oil and natural gas commercially and in commercial quantities could be impaired." Should climate change or other drought conditions occur, our ability to obtain water of a sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

Legislative and regulatory initiatives related to climate change and greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce, depressing the prices we receive for oil and natural gas. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have a material adverse effect on our business, financial condition and results of operations. Additionally, the threat of climate change has resulted in increasing political risk in the United States as various policy makers, regulatory agencies and political candidates at the federal, state and local levels have at times proposed bans of new leases for production of minerals on federal properties and various restrictions on hydraulic fracturing, including its outright prohibition. Should these or other limitations or prohibitions be imposed or continue to be applied, our oil and natural gas operations on federal lands could be adversely impacted.

Various policy makers, regulatory agencies and political candidates at the federal, state and local levels have identified climate change as a priority, and new executive orders, regulatory action and/or legislation targeting greenhouse gas emissions, promoting energy efficiency or the development and consumption of alternative forms of energy or prohibiting or restricting oil and natural gas development activities in certain areas, have been, or may in the future be, proposed and/or promulgated. While the Trump administration has revoked multiple Biden administration executive orders and rules regarding climate change, a future administration, or a state or local government, may impose new restrictions related to climate change and greenhouse gas emissions. For further discussion of these executive orders and other legislative and regulatory developments regarding climate change, see "Business—Regulation—Oil and Natural Gas Regulation."

In any event, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of greenhouse gas emissions-related agreements, legislation and measures on our financial performance is highly uncertain because we are unable to predict, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and trade-offs that inevitably occur in connection with such processes.

New climate disclosure rules adopted by the SEC or states in which we have operations or do business could increase our costs of compliance and adversely impact our business.

On March 6, 2024, the SEC adopted new rules that would require significantly expanded climate-related disclosures in SEC filings, including certain climate-related risks, climate-related metrics and greenhouse gas emissions, information about

climate-related targets and goals, transition plans, if any, and extensive attestation requirements (the "SEC Climate Disclosure Rules"). The SEC Climate Disclosure Rules included certain phase-in compliance dates for disclosure of material Scope 1 and 2 greenhouse gas emissions. Litigation challenging the SEC Climate Disclosure Rules was filed by multiple parties in multiple jurisdictions, which was consolidated and assigned to the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the SEC issued an order staying implementation of the SEC Climate Disclosure Rules while the U.S. Court of Appeals considered the litigation. On March 27, 2025, the SEC voted to end its defense of the SEC Climate Disclosure Rules in the litigation, and on July 23, 2025, it filed a status report requesting that the U.S. Court of Appeals proceed with the case and issue an opinion on the challenges to the climate disclosure rules. On September 12, 2025, the U.S. Court of Appeals denied the SEC's request to proceed with the case and indicated that the case would be held in abeyance until the SEC either renews its defense of the rules or revises the rules through notice-and-comment rulemaking. Accordingly, it is not clear whether, when or in what form the SEC Climate Disclosure Rules will be implemented or the ultimate timing of required compliance with such rules, and at this time we cannot predict the costs of implementation or any potential adverse impacts resulting from the SEC Climate Disclosure Rules. In addition, in the absence of federal action, states may propose and adopt climate disclosure requirements.

In the event the states in which we operate or do business adopt climate disclosure requirements or the SEC in the future adopts climate disclosure rules that apply to us, we could incur significant additional costs relating to the assessment and disclosure of climate-related risks, including costs relating to monitoring, collecting, analyzing and reporting the new metrics and implementing systems and procuring additional internal and external personnel with the requisite skills and expertise to serve those functions. These additional costs or changes in operations could have a material adverse effect on our business, financial condition, results of operations and cash flows. We may also face increased litigation risks related to disclosures made pursuant to any such regulations. In addition, enhanced climate disclosure requirements could accelerate the trend of certain investors and lenders restricting or seeking more stringent conditions with respect to their investments in carbon-intensive sectors.

New regulations on all emissions from our operations could cause us to incur significant costs.

In recent years, the EPA issued final rules to subject oil and natural gas operations to regulation under the NSPS and NESHAP programs under the CAA and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured oil and natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules have required changes to our operations, including the installation of new equipment to control emissions. In April 2024, the EPA issued a final consent decree that established a December 10, 2024 deadline for the EPA to review and propose revisions to the NESHAP for oil and natural gas production facilities and natural gas transmission and storage facilities, which may require us to make additional changes to our operations. The EPA has not yet proposed any such revisions. In addition, the EPA finalized a more stringent National Ambient Air Quality Standard for ozone in October 2015. To the extent regions reclassified as non-attainment areas under the lower ozone standard have begun implementing new, more stringent regulations, those regulations could also apply to our or San Mateo's customers' operations. The IRA contains a suite of provisions addressing onshore and offshore oil and natural gas development under federal leases. Under the authority of the IRA, on April 10, 2024, BLM finalized new regulations to reduce the waste of natural gas from venting, flaring and leaks during oil and natural gas production activities on Federal and Indian leases. The North Dakota federal district court enjoined enforcement of the regulations in Texas, North Dakota, Montana, Wyoming, and Utah. The injunction was appealed to the U.S. Court of Appeals for the Eighth Circuit, but the appeal has been held in abeyance since February 14, 2025. In November 2025, BLM announced that it will delay enforcement of provisions of the rule that had been scheduled to take effect in December 2025. These rules are expected to result in an increase to our operating costs and changes in our operations. In December 2023, the EPA issued final NSPS updates and emission guidelines to reduce methane and other pollutants from the oil and gas industry. In addition, several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. The EPA issued a final rule on October 22, 2024, removing the affirmative defense for violations caused by malfunctions from the NESHAP for the oil and natural gas production source category and natural gas transmission and storage source category. On November 18, 2024, the EPA published a final rule under authority of the IRA that imposes a waste emissions charge on large emitters of waste methane from the oil and gas sector. The rule was nullified pursuant to a Joint Resolution of Disapproval under the Congressional Review Act signed by President Trump in March 2025, and the EPA issued a final rule in May 2025 removing the waste emissions charge rules from the Code of Federal Regulations. However, the underlying statute mandating the waste emissions charge remains in effect, though collection of the charge under that law with respect to the oil and gas sector has been delayed until 2034. As a result of this continued regulatory focus, these and any future federal and state regulations of the oil and natural gas industry could result in increased compliance costs for our operations.

We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

Our pipelines are subject to stringent and complex regulation related to pipeline safety and integrity management. For instance, the Department of Transportation, through PHMSA, has established a series of rules that require pipeline operators to develop and implement integrity management programs for hazardous liquid (including oil) pipeline segments that, in the event

of a leak or rupture, could affect high-consequence areas. The Rustler Breaks Oil Pipeline System and the Trophy Pipeline System are subject to such rules. PHMSA also recently finalized rulemaking to expand existing integrity management, reporting and records retention, and safety requirements to certain natural gas transmission lines. Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies such as the RRC and the NMOCD could result in substantial expenditures for testing, repairs and replacement. Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial position.

A change in the jurisdictional characterization of some of our assets by FERC or a change in policy by FERC may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC under the NGA. 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 FERC regulation. 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. Similarly, intrastate crude oil pipeline facilities are exempt from regulation by FERC under the ICA. San Mateo's Rustler Breaks Oil Pipeline System, which includes crude oil gathering and transportation pipelines from origin points in Eddy County, New Mexico to an interconnect with Plains, and our Trophy Pipeline System, which includes crude oil gathering and transportation pipelines from origin points in Lea County, New Mexico to various interconnects with third parties, are subject to FERC jurisdiction. We believe the other crude oil pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as an intrastate facility not subject to FERC regulation. Whether a pipeline provides service in interstate commerce or intrastate commerce is highly fact dependent and determined on a case-by-case basis. A change in the jurisdictional characterization of our facilities by FERC, the courts or Congress, a change in policy by FERC or Congress or the expansion of our activities may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

The rates of our regulated assets are subject to review and reporting by federal regulators, which could adversely affect our revenues.

The Rustler Breaks Oil Pipeline System and the Trophy Pipeline System transport crude oil in interstate commerce. FERC regulates the rates, terms and conditions of service on pipelines that transport crude oil in interstate commerce. If a party with an economic interest were to file either a complaint against our tariff rates or protest any proposed increases to our tariff rates, or FERC were to initiate an investigation of our rates, then our rates could be subject to detailed review. If any proposed rate increases were found by FERC to be in excess of just and reasonable levels, FERC could order us to reduce our rates and to refund the amount by which the rate increases were determined to be excessive, plus interest. If our existing rates were found by FERC to be in excess of just and reasonable levels, we could be ordered to refund the excess we collected for up to two years prior to the date of the filing of the complaint challenging the rates, and we could be ordered to reduce our rates prospectively. In addition, a state commission also could investigate our intrastate rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our rates exceeded levels justified by our cost of service, the state commission could order us to reduce our rates. Any such reductions may result in lower revenues and cash flows.

In addition, FERC's ratemaking policies are subject to change and may impact the rates charged and revenues received on the Rustler Breaks Oil Pipeline System, the Trophy Pipeline System and any other natural gas or crude oil pipeline that is determined to be under the jurisdiction of FERC.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to approximately $1.3 million per day for each violation and disgorgement of profits associated with any violation. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. While the nature of our gathering facilities is such that these facilities have not yet been regulated by FERC, the Rustler Breaks Oil Pipeline System and Trophy Pipeline System do transport crude oil in interstate commerce and, therefore, are subject to FERC regulation. Laws, rules and regulations pertaining to those and other matters may be considered or adopted by FERC or Congress from time to time. Failure to comply with those laws, rules and regulations in the future could subject us to civil penalty liability.

Derivatives legislation adopted by Congress could have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), among other things, established federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when, or if, this will be accomplished. For example, the CFTC has proposed, but not finalized, rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The Dodd-Frank Act could also result in additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future.

If these types of commodity hedges become unavailable or uneconomic, our commodity price risk could increase, which would increase the volatility of revenues and may decrease the amount of credit available to us. Any limitations or changes in our use of derivative arrangements could also materially affect our cash flows, which could adversely affect our ability to make capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

Changes in U.S. foreign trade policies, including the imposition of additional tariffs and other trade barriers, and efforts to withdraw from or materially modify international trade agreements, may materially and adversely affect our business, operations and financial condition.

U.S. foreign trade policy continues to evolve, and recent actions have resulted in the imposition of new and increased tariffs, as well as other trade barriers on the foreign import of certain materials and products. For example, in April 2025, the U.S. government announced a new tariff regime that included a 10% baseline tariff on most products imported from other countries and an additional individualized reciprocal tariff on the countries with which the U.S. has the largest trade deficits, including China. Since that time, the U.S. expanded tariffs on key industrial inputs, including tariffs on steel and aluminum imports, and at times announced, rescinded, modified and temporarily suspended multiple tariffs on several foreign jurisdictions, which increased uncertainty regarding the ultimate effect of the tariffs on economic conditions. In August 2025, however, the U.S. Court of Appeals for the Federal Circuit ruled that the tariffs imposed under the Trump Administration exceed presidential authority and therefore are invalid, and in February 2026, the U.S. Supreme Court affirmed such decision. Following the ruling, the Trump Administration signed an executive order imposing a 10% "global tariff" and later indicated an intention to increase such "global tariff" to 15%, effective immediately, using presidential powers under certain U.S. trade laws. If implemented, such tariffs can remain in effect for up to 150 days, which may be extended by the U.S. Congress. The Trump Administration may continue to impose additional tariffs under other U.S. trade laws. In addition, from time to time, certain leaders in the U.S. government, including in the Trump administration, have indicated a willingness to revise, renegotiate or terminate various existing bilateral and multilateral trade agreements. The uncertainty over such policies has caused volatility in commodity, capital and financial markets, increased concerns over domestic and global inflation and adversely impacted consumer confidence in the U.S and worldwide. Any future tariffs or other trade restrictions may lead to continuing uncertainty and volatility in U.S. and global financial and economic conditions and commodity markets, declining consumer confidence, significant inflation and diminished expectations for the economy, and ultimately reduced demand for oil and natural gas.

Changes in tariffs and trade restrictions can be announced with little or no advance notice. We cannot predict what additional changes to trade policy or tariffs will be made by the Trump administration, Congress or other governments, including whether existing or new tariff policies will be maintained or modified, what materials or products may be subject to such policies or whether the entry into new bilateral or multilateral trade agreements, or the amendment or termination of existing trade agreements, will occur, nor can we predict the effects that any such changes would have on our business. However, such steps, if adopted, could increase our costs, disrupt supply chains, delay project timelines or otherwise adversely impact our business and operations. For example, price increases for the materials we and San Mateo use in the construction of our midstream assets may result in increased costs associated with the continued build-out of such assets, as well as projects under development. Because our midstream business generates substantially all of its revenue under commercial agreements with customers that provide for fixed-fee structures, our midstream business will generally be unable to pass these cost increases along to our customers, and our income from operations and cash flows may be adversely affected.

In addition, changes in U.S. trade policy and tariffs have resulted, and could again result, in reactions from U.S. trading partners, including adopting responsive trade policies making it more difficult or costly for us to conduct business across the jurisdictions in which we operate. For example, in response to the U.S. government's additional tariff on imports from China, on February 4, 2025, the Chinese government announced that it would implement tariffs on certain goods being imported into China from the U.S. Similar responsive measures have been announced or implemented by other countries affected by U.S. trade actions. There can be no assurance that such changes in U.S. or foreign trade policy or tariffs or in laws and policies governing foreign trade, and any resulting negative sentiments or retaliatory trade practices towards the United States as a result of such changes, would not materially and adversely affect our business, financial condition, results of operations and liquidity.

Risks Related to Our Common Stock

The price of our common stock has fluctuated substantially and may fluctuate substantially in the future.

Our stock price has experienced volatility and could vary significantly as a result of a number of factors. In 2025, our stock price fluctuated between a high of $64.05 and a low of $35.19. In addition, the trading volume of our common stock may continue to fluctuate and cause significant price variations to occur. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. In addition, the stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Attention to environmental, social and governance ("ESG") and conservation matters and a negative shift in market perception towards the oil and natural gas industry could adversely affect demand for oil and natural gas and our stock price.

Attention from governmental and regulatory bodies, investors, consumers and other stakeholders on ESG practices, together with changes in consumer, industrial and commercial behavior, investor and societal expectations on companies to address climate change and to make voluntary disclosures related to climate change and sustainability, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons and the use of products manufactured with, or powered, by hydrocarbons, may result in the enactment of climate and ESG-related regulations, policies and initiatives at the government, regulator, corporate and/or investor community levels; technological advances with respect to the generation, transmission, storage and consumption of energy; and the development of, and increased demand from consumers for, lower-emission products and services. These developments may in the future result in increased costs (including increased costs associated with compliance, shareholder engagement, contracting and insurance) and reduced demand for products manufactured with, or powered by, petroleum products, as well as the demand for our products and services. Such developments could result in downward pressure on the stock prices of oil and natural gas companies, including ours.

In addition, negative perceptions regarding our industry and reputational risks, including perceptions related to the sufficiency of our ESG program (which may include policies, practices and extralegal objectives related to climate change, environmental stewardship, social responsibility and corporate governance), may in the future adversely affect our ability to successfully carry out our business strategy by adversely affecting our access to capital. In particular, certain segments of the investor community have at times expressed negative sentiment towards investing in the oil and natural gas industry. There have also been efforts in recent years to influence the investment community, including investment advisors, investment fund managers, pension funds, sovereign wealth funds, university endowments, individual investors and family foundations, to divest, or limit investment in, fossil fuel-related equities. As a result, some investors have adopted policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Other significant investors and asset managers, both domestically and internationally, have published ESG guidelines and disclosure standards that companies in which they invest are expected to adopt or follow.

Certain other stakeholders have pressured commercial and investment banks and other capital providers to stop or limit funding of oil and natural gas projects and have pressured insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Institutional lenders that provide financing to energy companies have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. With the continued volatility in oil and natural gas prices and elevated interest rates, which have increased the cost of borrowing, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially those primarily focused in the shale plays. This may result in an increase in our expenses and a reduction of revenues and available capital funding for potential development projects, further impacting our future financial results. Furthermore, if we are unable to achieve the desired level of capital efficiency or free cash flow within the timeframe expected by the market, our stock price may be adversely affected.

In addition, shareholder activism has been recently increasing in the oil and gas industry, and shareholders may attempt to effect changes to our business or governance, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters, and such ratings are used by some investors to

inform their investment and voting decisions. Unfavorable ESG ratings and activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and to the diversion of investment to other industries, which could have an adverse effect on our stock price and our access to and costs of capital.

Future sales of shares of our common stock by existing shareholders and future offerings of our common stock by us could depress the price of our common stock.

The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the market, including shares of equity or debt securities convertible into common stock, and the perception that these sales could occur may also depress the market price of our common stock. Sales of our common stock may make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. These sales could also cause our stock price to decrease and make it more difficult for you to sell shares of our common stock.

We may also sell or issue additional shares of common stock or equity or debt securities convertible into common stock in public or private offerings or in connection with acquisitions. We cannot predict the size of future issuances of our common stock or convertible securities or the effect, if any, that future issuances and sales of shares of our common stock or convertible securities would have on the market price of our common stock.

Our directors and executive officers own a significant percentage of our equity, which could give them influence in corporate transactions and other matters, and their interests could differ from other shareholders.

As of February 24, 2026, our directors and executive officers beneficially owned approximately 5.8% of our outstanding common stock. These shareholders could influence or control to some degree the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of formation or bylaws and the approval of mergers and other significant corporate transactions. Their influence or control of the Company may have the effect of delaying or preventing a change of control of the Company and may adversely affect the voting and other rights of other shareholders. In addition, due to their ownership interest in our common stock, our directors and executive officers may be able to remain entrenched in their positions.

Our Board can authorize the issuance of preferred stock, which could diminish the rights of holders of our common stock and make a change of control of the Company more difficult even if it might benefit our shareholders.

Our Board is authorized to issue shares of preferred stock in one or more series and to fix the voting powers, preferences and other rights and limitations of the preferred stock. Accordingly, we may issue shares of preferred stock with a preference over our common stock with respect to dividends or distributions on liquidation or dissolution, or that may otherwise adversely affect the voting or other rights of the holders of common stock.

Issuances of preferred stock, depending upon the rights, preferences and designations of the preferred stock, may have the effect of delaying, deterring or preventing a change of control of the Company, even if that change of control might benefit our shareholders.

General Risk Factors

We may have difficulty managing growth in our business, which could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Because of our size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As and when we expand our activities, including our midstream business, through San Mateo or otherwise, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers, landmen, midstream professionals, attorneys and financial and accounting professionals, could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Our success depends, to a large extent, on our ability to retain our key personnel, including our chairman and chief executive officer, management and technical team and the members of our Board, and the loss of any key personnel or Board member could disrupt our business operations.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, evaluating and developing prospects and reserves. Our performance and success are dependent to a large extent on the efforts and continued employment of our management and technical personnel, including our Chairman and Chief Executive Officer, Joseph Wm. Foran. We do not believe that these individuals could be quickly replaced with personnel of equal experience and capabilities, and their successors may not be as effective. We have entered into employment agreements with Mr. Foran and other key personnel. However, these employment agreements do not ensure that

these individuals will remain in our employment. If Mr. Foran or other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. With the exception of Mr. Foran, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have an active Board that meets at least quarterly throughout the year and is closely involved in our business and the determination of our operational strategies. Members of our Board work closely with management to identify potential prospects, acquisitions and areas for further development. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and, as a result, our operations may be adversely affected.

Although overall labor market conditions in the U.S. have moderated from the extremes experienced during and immediately following the COVID-19 pandemic, many companies in our industry continue to report challenges in attracting and retaining qualified personnel, which has resulted in increased costs to attract skilled labor, such as higher wages or costs for contractors. We may experience employee turnover or labor shortages if our business requirements, compensation, benefits and/or perquisites are inconsistent with the expectations of current or prospective employees, or if workers pursue employment in fields with less volatility than in the energy industry. If we are unsuccessful in our efforts to attract and retain sufficient qualified personnel on terms acceptable to us, or do so at rates necessary to maintain our competitive position, our business could be adversely affected.

A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss.

Our business, like the oil and natural gas industry in general, is dependent on digital technologies to conduct certain exploration, development, production, gathering, processing and financial activities, including technologies that are managed by third-party service providers or other providers to our industry on whom we directly or indirectly rely to help us collect, host or process information. We depend on such digital technology to, among other things, estimate oil and natural gas reserves quantities, plan, execute and analyze drilling, completion, production, gathering, processing and disposal operations, process and record financial and operating data and communicate with employees, shareholders, royalty owners and other third-party industry participants. Industrial control systems, such as our SCADA systems, control important processes and facilities that are critical to our operations.

While we and our third-party service providers commit resources to the design, implementation and monitoring of our information systems, there is no guarantee that these security measures will provide absolute security. Despite these security measures, we may not be able to anticipate, detect or prevent cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until launch, and because attackers are increasingly using technologies designed to circumvent controls and avoid detection. Security incidents can also occur as a result of non-technical issues, such as physical theft. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches, ransomware or other malware, phishing or social engineering schemes or attacks or other cybersecurity threats or attacks, possible consequences include financial losses, damage to our reputation and the inability to engage in any of the aforementioned activities. Any such consequence could have a material adverse effect on our business. In addition, any failure of our third-party providers' computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business. Moreover, the rapid advancement and increased adoption of artificial intelligence and machine learning technologies has given rise to additional vulnerabilities and potential entry points for cyberattacks, including a risk of exposure of confidential, proprietary or other sensitive information through the inadvertent use of open artificial intelligence tools. These technologies can be exploited by malicious actors to enhance the sophistication, scale or intensity of cyberattacks, making it more challenging to detect and mitigate such threats.

While we have experienced certain phishing schemes and efforts to access our network, we have not experienced any material losses due to cyber incidents. However, we may suffer such losses in the future. If our or our third-party providers' systems for protecting against cyber incidents prove to be insufficient, we could be adversely affected by unauthorized access to proprietary or other sensitive information, which could lead to data corruption, communication interruption, exposure of our or third parties' confidential or proprietary information, disruptions of our current or planned business operations or transactions, damage to our reputation or financial loss. Additionally, costs for insurance may also increase as a result of cybersecurity threats, and insurance against losses relating to cyber incidents may become more difficult to obtain.

As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and further enhance our protective systems or to investigate and remediate any vulnerabilities. In addition, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, mitigation and notification, which could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. New laws and regulations governing data privacy and the unauthorized disclosure of personal or confidential information may also pose compliance challenges and could elevate our costs. Any failure by us to comply with any additional regulations could result in significant penalties and liability to us, and we cannot predict the potential impact to

our business or the energy industry resulting from additional regulations. We may also be subject to regulatory investigations or litigation relating to cybersecurity issues.

Provisions of our certificate of formation, bylaws and Texas law may have anti-takeover effects that could prevent a change in control even if it might be beneficial to our shareholders.

Our certificate of formation and bylaws contain certain provisions that may discourage, delay or prevent a merger or acquisition of the Company or other change in control transaction that our shareholders may consider favorable. These provisions include:

- authorization for our Board to issue preferred stock without shareholder approval;
- a classified Board so that not all members of our Board are elected at one time;
- the prohibition of cumulative voting in the election of directors; and
- a limitation on the ability of shareholders to call special meetings to those owning at least 25% of our outstanding shares of common stock.

Provisions of Texas law may also discourage, delay or prevent someone from acquiring or merging with us, which may cause the market price of our common stock to decline. Under Texas law, a shareholder who beneficially owns more than 20% of our voting stock, or an affiliated shareholder, cannot acquire us for a period of three years from the date this person became an affiliated shareholder, unless various conditions are met, such as approval of the transaction by our Board before this person became an affiliated shareholder or approval of the holders of at least two-thirds of our outstanding voting shares not beneficially owned by the affiliated shareholder.

We operate in a litigious environment and may be involved in legal proceedings that could have a material adverse effect on our results of operations and financial condition.

Like many oil and natural gas companies, we are from time to time involved in various legal and other proceedings in the ordinary course of business, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have a material adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 1C. Cybersecurity.

Risk Management and Strategy

The Company recognizes the importance of developing, implementing and maintaining cybersecurity measures to better safeguard our information systems and protect the confidentiality, integrity and availability of our data.

Managing Material Risks and Integrated Overall Risk Management

The Company has integrated cybersecurity into our broader risk management framework. Our risk management team works closely with our IT department to evaluate and address cybersecurity risks in alignment with our business objectives and operational needs. The Company requires the Board and employees to complete cybersecurity training related to the physical security of assets, data privacy and other information security policies and procedures.

Engage Third Parties on Risk Management

Recognizing the complexity and evolving nature of cybersecurity threats, the Company engages with a range of external experts, including cybersecurity consultants in evaluating and testing our risk management systems. Our collaboration with these third parties includes regular audits, threat assessments, penetration tests and consultation on security enhancements.

Oversee Third-Party Risk

Because we are aware of the risks associated with third-party vendors, service providers and business partners, we have implemented processes to oversee and manage these risks. We conduct initial risk assessments of third-party providers before engagement. These assessments include due diligence reviews of third parties that have access to our networks, confidential information and information systems in order to assess the risks from cybersecurity threats. This approach is designed to mitigate risks related to data breaches or other security incidents originating from third parties.

Risks from Cybersecurity Threats

As of February 24, 2026, we were not aware of any cybersecurity threats or incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations or financial standing. However, there can be no assurance that our cybersecurity processes will prevent or mitigate cybersecurity incidents or threats and that our efforts will always be successful. For further discussion regarding our cybersecurity risks, see "Risk Factors—General Risk Factors—A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss."

Governance

The Company is aware of the critical nature of managing risks associated with cybersecurity threats and has established oversight mechanisms at the Board and management levels to ensure effective governance in managing risks associated with cybersecurity threats.

Board Oversight

The Board has oversight of cybersecurity risks and, specifically, the Audit Committee of the Board is charged with the oversight of the Company's guidelines and policies to govern the process by which risk assessment and risk management are undertaken by management, including with respect to cybersecurity risks. Our Board is composed of members with diverse expertise, including risk management, technology and finance, which experience provides them with the skills needed to oversee cybersecurity risks effectively.

Management's Role Managing Risk

The Company's IT Committee, which includes senior executives and other members of management, meets regularly to monitor and discuss cybersecurity issues. The Senior Vice President of Information Technology, the Executive Vice President and Chief Financial Officer ("CFO") and the Co-President, Chief Legal Officer and Head of M&A ("CLO") play a pivotal role in informing the Board on cybersecurity risks. They provide comprehensive briefings to the Board on a regular basis, with a minimum frequency of once per year. These briefings encompass a broad range of topics, including:

- current cybersecurity landscape and emerging threats;
- status of ongoing cybersecurity initiatives and strategies;
- incident reports and learnings from any cybersecurity events; and
- compliance with regulatory requirements and industry standards.

In addition to our scheduled meetings, the Board, Senior Vice President of Information Technology, CFO and CLO maintain an ongoing dialogue regarding emerging or potential cybersecurity risks. Together, they receive updates on significant developments in the cybersecurity domain, ensuring the Board's oversight is proactive and responsive. The Board actively participates in strategic decisions related to cybersecurity, offering guidance and approval for major initiatives. This involvement ensures that cybersecurity considerations are integrated into the broader strategic objectives of the Company.

Risk Management Personnel

Primary responsibility for assessing, monitoring and managing our cybersecurity risks rests with the Senior Vice President of Information Technology. With over 35 years of experience in the information technology field, he brings a wealth of expertise to his role. His in-depth knowledge and experience are instrumental in developing and executing our cybersecurity strategies. Our Senior Vice President of Information Technology tests our compliance with standards, remediates known risks and leads our employee training program.

Reporting to the Board

The Senior Vice President of Information Technology regularly informs the Chief Executive Officer and Chief Legal Officer of all aspects related to cybersecurity risks and incidents. This ensures that the highest levels of management are kept abreast of the cybersecurity posture and potential risks facing the Company. Furthermore, significant cybersecurity matters and

strategic risk management decisions are escalated to the Board, ensuring the Board has comprehensive oversight and can provide guidance on critical cybersecurity issues.

Monitor Cybersecurity Incidents

The Senior Vice President of Information Technology monitors the latest developments in cybersecurity, including potential threats and innovative risk management techniques. The Senior Vice President of Information Technology implements and oversees processes for the regular monitoring of our information systems. This includes the deployment of advanced security measures and regular system audits to identify potential vulnerabilities. In the event of a cybersecurity incident, the Senior Vice President of Information Technology is equipped with an incident response plan. This plan includes immediate actions to mitigate the impact and long-term strategies for remediation and prevention of future incidents.

Item 2. Properties.

See "Business" for descriptions of our properties. We also have various operating leases for rental of office space and office and field equipment. See Note 4 to the consolidated financial statements in this Annual Report for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings.

We are party to several legal proceedings encountered in the ordinary course of business. While the ultimate outcome and impact on us cannot be predicted with certainty, in the opinion of management, it is remote that these legal proceedings will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

General Market Information

Shares of our common stock are traded on the NYSE under the symbol "MTDR." Our shares have been traded on the NYSE since February 2, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On February 24, 2026, we had 124,249,941 shares of common stock outstanding held by approximately 444 record holders, excluding shareholders for whom shares are held in "nominee" or "street" name.

Dividends

In each of the first, second and third quarters of 2025, our Board declared quarterly cash dividends of $0.3125 per share of common stock. In October 2025, the Board amended our dividend policy to increase the quarterly dividend to $0.375 per share of common stock and also declared a quarterly cash dividend of $0.375 per share of common stock. In February 2026, the Board declared a quarterly cash dividend of $0.375 per share of common stock payable on March 10, 2026 to shareholders of record as of February 27, 2026. We expect that, based on current circumstances, comparable cash dividends will continue to be paid in the foreseeable future.

Equity Compensation Plan Information

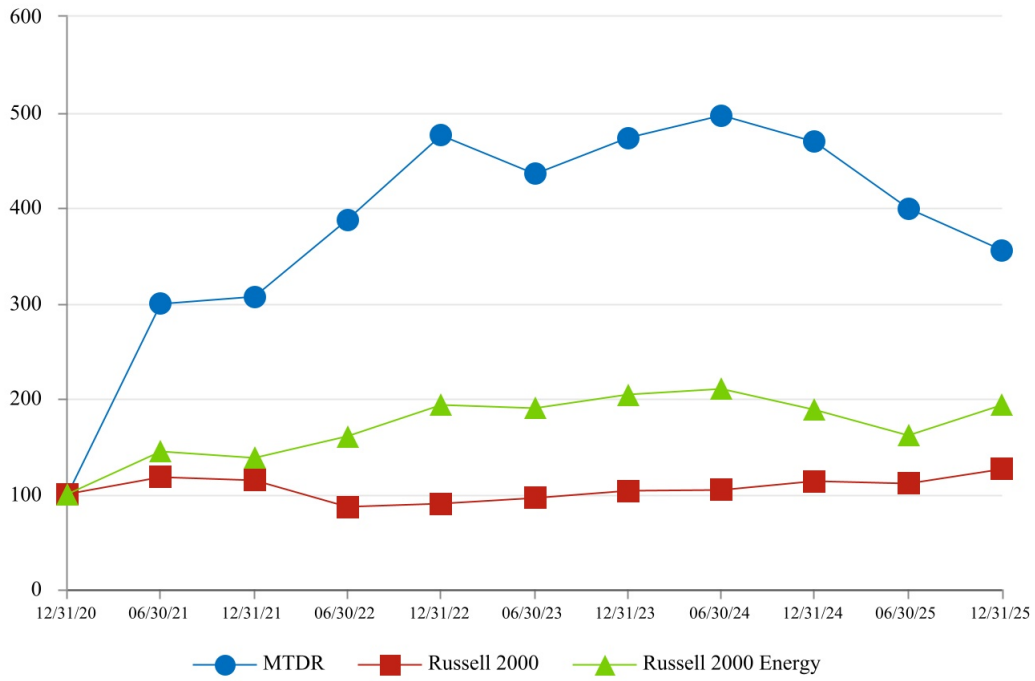
Certain information regarding securities authorized for issuance under our equity compensation plans is included under the caption "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" in Part III, Item 12 of this Annual Report and is incorporated herein by reference.

Share Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from December 31, 2020 through December 31, 2025, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the Russell 2000 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed.

This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before, on, or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC's disclosure rules. This historic stock performance is not indicative of future stock performance.

Comparison of Cumulative Total Return Among
Matador Resources Company, the Russell 2000 Index
and the Russell 2000 Energy Index



Repurchase of Equity by the Company or Affiliates

The following table contains information about our acquisition of common stock during the quarter ended December 31, 2025.

Period	Total Number of Shares Purchased[1][2]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	Maximum Number (or Approximate Dollar Value in thousands) of Shares that May Yet Be Purchased under the Plans or Programs[2]
October 1, 2025 to October 31, 2025	98,564	$ 44.41	98,500	344,916
November 1, 2025 to November 30, 2025	20,402	38.28	20,000	344,150
December 1, 2025 to December 31, 2025	394	45.22	—	344,150
Total	119,360	$ 43.36	118,500	

(1) During the fourth quarter of 2025, the Company re-acquired 860 shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.
(2) In April 2025, the Board approved the Share Repurchase Program authorizing the repurchase of up to $400.0 million of common stock. During the fourth quarter of 2025, the Company repurchased 118,500 shares of common stock under the Share Repurchase Program at a weighted average price of $43.38 per common share for a total cost of $5.1 million, excluding accrued excise tax of $0.1 million.

Item 6. Selected Financial Data.

Not applicable.

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 our consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results, and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in oil or natural gas prices, the timing of planned capital expenditures, availability under our Credit Agreement and the San Mateo Credit Facility, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting our oil and natural gas and midstream operations, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of gathering, processing and transportation facilities, availability and integration of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere 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 not occur. See "Cautionary Note Regarding Forward-Looking Statements."

For a comparison of our results of operations for the years ended December 31, 2024 and December 31, 2023, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2024, filed with the SEC on February 25, 2025.

Overview

We are an independent energy company founded in July 2003 engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also have operations in the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, we conduct midstream operations in support of, and to provide flow assurance for, our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and produced water gathering services and produced water disposal services to third parties.

2025 Operational Highlights

During the year ended December 31, 2025, we completed and began producing oil and natural gas from 151 gross (121.2 net) operated and 107 gross (8.1 net) horizontal non-operated wells in the Delaware Basin. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana during 2025, although we did participate in the drilling and completion of 12 gross (0.1 net) non-operated Haynesville shale wells that began producing in 2025.

We have built significant optionality into our drilling program, which should generally allow us to decrease or increase the number of rigs we operate as necessary based on changing commodity prices and other factors. We were able to achieve D/C/E capital expenditures for 2025 of $1.53 billion, which was within our estimated range for 2025 D/C/E capital expenditures of $1.47 to $1.55 billion, as provided on October 21, 2025.

Substantially all of our 2025 capital expenditures were directed to (i) the further delineation and development of our leasehold position in the Delaware Basin, (ii) the acquisition, construction, installation and maintenance of midstream assets, (iii) our participation in non-operated wells and (iv) the acquisition of additional producing properties, leasehold and mineral interests prospective for the Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin.

Our average daily oil equivalent production for the year ended December 31, 2025 was 207,070 BOE per day, including 119,723 Bbl of oil per day and 524.1 MMcf of natural gas per day, an increase of 21%, as compared to 170,751 BOE per day, including 99,808 Bbl of oil per day and 425.7 MMcf of natural gas per day, for the year ended December 31, 2024. Our average daily oil production in 2025 was 119,723 Bbl of oil per day, an increase of 20%, as compared to 99,808 Bbl of oil per day in 2024. This increase in oil production was primarily a result of our ongoing delineation and development drilling activities in the Delaware Basin. Our average daily natural gas production for the year ended December 31, 2025 was 524.1 MMcf per day, an increase of 23%, as compared to 425.7 MMcf per day in 2024. This increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Oil production comprised 58% of our total production for each of the years ended December 31, 2025 and 2024.

For the year ended December 31, 2025, our oil and natural gas revenues were $3.24 billion, an increase of 3% from oil and natural gas revenues of $3.14 billion for the year ended December 31, 2024. Our oil revenues increased 2% to $2.84 billion,

as compared to $2.77 billion for the year ended December 31, 2024. The increase in oil revenues resulted from the 20% increase in our oil production noted above, which was partially offset by a 14% decrease in the weighted average oil price realized for the year ended December 31, 2025 to $64.99 per Bbl, as compared to $75.89 per Bbl realized for the year ended December 31, 2024. Our natural gas revenues increased 7% to $398.6 million, as compared to $371.5 million for the year ended December 31, 2024. The increase in natural gas revenues resulted from a 23% increase in natural gas production for the year ended December 31, 2025 noted above, which was partially offset by a decrease in our weighted average realized natural gas price of $2.08 per Mcf in 2025, as compared to $2.38 per Mcf in 2024.

We reported net income attributable to Matador shareholders of approximately $759.2 million, or $6.09 per diluted common share, on a GAAP basis for the year ended December 31, 2025, as compared to a net income of $885.3 million, or $7.14 per diluted common share, for the year ended December 31, 2024. Adjusted EBITDA for the year ended December 31, 2025 was $2.29 billion, as compared to Adjusted EBITDA of $2.30 billion for the year ended December 31, 2024. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income and net cash provided by operating activities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures."

At December 31, 2025, our estimated total proved oil and natural gas reserves were 667.0 million BOE, including 376.0 million Bbl of oil and 1.75 Tcf of natural gas, with a Standardized Measure of $6.99 billion and a PV-10 of $8.24 billion. At December 31, 2024, our estimated total proved oil and natural gas reserves were 611.5 million BOE, including 361.8 million Bbl of oil and 1.50 Tcf of natural gas, with a Standardized Measure of $7.38 billion and a PV-10 of $9.23 billion. Our estimated total proved reserves of 667.0 million BOE at December 31, 2025 represented a 9% year-over-year increase, as compared to 611.5 million BOE at December 31, 2024. Our estimated proved oil reserves were 376.0 million Bbl at December 31, 2025, an increase of 4%, as compared to 361.8 million Bbl at December 31, 2024, and our estimated proved natural gas reserves were 1.75 Tcf at December 31, 2025, an increase of 17%, as compared to 1.50 Tcf at December 31, 2024. Proved oil reserves comprised 56% of our total proved reserves at December 31, 2025, as compared to 59% at December 31, 2024. At December 31, 2025, 61% of our total proved reserves were proved developed reserves, as compared to 60% at December 31, 2024. At December 31, 2025, approximately 99% of our total proved oil and natural gas reserves were attributable to our properties in the Delaware Basin.

At both December 31, 2025 and December 31, 2024, these reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business—Estimated Proved Reserves."

2025 Midstream Highlights

San Mateo achieved strong operating results in 2025, highlighted by (i) free cash flow generation, (ii) increased midstream services revenues and (iii) increased natural gas gathering and processing volumes, produced water handling volumes and oil gathering and transportation volumes. San Mateo is owned 51% by us and 49% by our joint venture partner, Five Point.

During the second quarter of 2025, San Mateo completed the expansion of the Marlan Processing Plant by adding a designed inlet capacity of 200 MMcf per day, including a nitrogen rejection unit and additional related facilities. This expansion increased the total capacity of the Marlan Processing Plant to 260 MMcf of natural gas per day.

At December 31, 2025, San Mateo's midstream system included:

- Natural Gas Assets: 720 MMcf per day of designed natural gas cryogenic processing capacity and approximately 340 miles of natural gas gathering pipelines in Eddy and Lea Counties, New Mexico and Loving County, Texas, including 43 miles of large diameter natural gas gathering lines spanning from the Stateline asset area to the Greater Stebbins Area in Eddy County, New Mexico;
- Oil Assets: three oil CDPs with over 100,000 Bbl of designed oil throughput capacity and approximately 120 miles of oil gathering and transportation pipelines in Eddy County, New Mexico and Loving County, Texas, as well as a 400,000-acre joint development area with Plains to gather our and other producers' oil production in Eddy County, New Mexico; and
- Produced Water Assets: 16 commercial salt water disposal wells and associated facilities with designed produced water disposal capacity of 475,000 Bbl per day and approximately 195 miles of produced water gathering pipelines in Eddy County, New Mexico and Loving County, Texas.

2026 Capital Expenditure Budget

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures in 2026. We have built significant optionality into our drilling program, which should generally allow us to decrease or increase the number of rigs we operate as necessary based on changing commodity prices and other factors. Our 2026 estimated capital expenditure budget consists of $1.35 to $1.44 billion for D/C/E capital expenditures and $100.0 to $110.0 million for midstream capital expenditures, which reflects our proportionate share of San Mateo's estimated 2026 capital expenditures as well as the estimated 2026 capital expenditures for other wholly-owned midstream projects. Substantially all of these 2026 estimated capital expenditures are expected to be allocated to (i) the further delineation and development of our leasehold position, (ii) the construction, installation and maintenance of midstream assets and (iii) our participation in certain non-operated well opportunities. Our 2026 Delaware Basin operated drilling program is expected to focus on the continued development of our various asset areas, with a continued emphasis on drilling and completing a high percentage of longer horizontal wells.

At December 31, 2025, we had $15.3 million in cash (excluding restricted cash) and $1.80 billion in undrawn borrowing capacity under the Credit Agreement (after giving effect to outstanding letters of credit based upon our elected borrowing commitment of $2.25 billion). We expect to fund our 2026 capital expenditures through a combination of cash on hand, operating cash flows and performance incentives paid to us by Five Point in connection with San Mateo. If capital expenditures were to exceed our operating cash flows in 2026, we expect to fund any excess capital expenditures, including for other significant acquisitions, through borrowings under the Credit Agreement or the San Mateo Credit Facility (assuming availability under such facilities) or through other capital sources, including borrowings under expanded or additional credit arrangements, the sale or joint venture of midstream assets, oil and natural gas producing assets, leasehold interests or mineral interests and potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all.

We intend to continue evaluating the opportunistic acquisition of producing properties, acreage and mineral interests and midstream assets, principally in the Delaware Basin. Purchase price multiples and per-acre prices can vary significantly based on the asset or prospect. As a result, it is difficult to estimate these capital expenditures with any degree of certainty; therefore, we have not provided estimated capital expenditures related to acquiring producing properties, acreage and mineral interests and midstream assets for 2026.

As we have done in recent years, we may divest portions of our non-core assets as well as consider monetizing other assets, such as certain midstream assets and mineral and royalty interests, as value-creating opportunities arise. Divestitures and other types of monetizations are difficult to estimate with any degree of certainty. Therefore, we have not provided estimated proceeds related to divestitures or monetizations for 2026.

Revenues

The following table summarizes our revenues and production data for the periods indicated.

	Year Ended December 31,		
	2025	2024	2023
Operating Data:			
Revenues (in thousands):[1]			
Oil	$ 2,840,167	$ 2,772,360	$ 2,144,894
Natural gas	398,583	371,474	400,705
Total oil and natural gas revenues	3,238,750	3,143,834	2,545,599
Third-party midstream services revenues	164,733	141,027	122,153
Sales of purchased natural gas	253,031	194,097	149,869
Realized gain (loss) on derivatives	21,679	12,724	(9,575)
Unrealized gain (loss) on derivatives	18,084	13,299	(1,261)
Total revenues	$ 3,696,277	$ 3,504,981	$ 2,806,785
Net Production Volumes:[1]			
Oil (MBbl)	43,699	36,530	27,542
Natural gas (Bcf)	191.3	155.8	123.4
Total oil equivalent (MBOE)[2]	75,581	62,495	48,112
Average daily production (BOE/d)[2]	207,070	170,751	131,813
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 64.99	$ 75.89	$ 77.88
Oil, with realized derivatives (per Bbl)	$ 64.99	$ 75.89	$ 77.88
Natural gas, without realized derivatives (per Mcf)	$ 2.08	$ 2.38	$ 3.25
Natural gas, with realized derivatives (per Mcf)	$ 2.20	$ 2.47	$ 3.17

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with NGLs are included with our natural gas revenues.

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Year Ended December 31, 2025 as Compared to Year Ended December 31, 2024

Oil and natural gas revenues. Our oil and natural gas revenues increased $94.9 million, or 3%, to $3.24 billion for the year ended December 31, 2025, as compared to $3.14 billion for the year ended December 31, 2024. Our oil revenues increased $67.8 million, or 2%, to $2.84 billion for the year ended December 31, 2025, as compared to $2.77 billion for the year ended December 31, 2024. This increase in oil revenues resulted from a 20% increase in our oil production to 43.7 million Bbl of oil for the year ended December 31, 2025, as compared to 36.5 million Bbl of oil for the year ended December 31, 2024, which was partially offset by a 14% decrease in the weighted average oil price realized for the year ended December 31, 2025 to $64.99 per Bbl, as compared to $75.89 per Bbl realized for the year ended December 31, 2024. Our natural gas revenues increased by $27.1 million, or 7%, to $398.6 million for the year ended December 31, 2025, as compared to $371.5 million for the year ended December 31, 2024. The increase in natural gas revenues was primarily attributable to a 23% increase in our natural gas production to 191.3 Bcf for the year ended December 31, 2025, as compared to 155.8 Bcf for the year ended December 31, 2024, which was partially offset by a 13% decrease in the weighted average natural gas price realized for the year ended December 31, 2025 to $2.08 per Mcf, as compared to $2.38 per Mcf realized for the year ended December 31, 2024.

Third-party midstream services revenues. Our third-party midstream services revenues increased $23.7 million, or 17%, to $164.7 million for the year ended December 31, 2025, as compared to $141.0 million for the year ended December 31, 2024. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. This increase was primarily attributable to (i) an increase in our third-party natural gas gathering and processing revenues to $90.3 million for the year ended December 31, 2025, as compared to $67.5 million for the year ended December 31, 2024, (ii) an increase in our oil transportation revenues to $23.7 million for the year ended December 31, 2025, as compared to $17.3 million for the year ended December 31, 2024, which were partially offset by (iii) a decrease in third-party produced water disposal revenues to $50.7 million for the year ended December 31, 2025, as compared to $56.3 million for the year ended December 31, 2024.

Sales of purchased natural gas. Our sales of purchased natural gas increased $58.9 million, or 30%, to $253.0 million for the year ended December 31, 2025, as compared to $194.1 million for the year ended December 31, 2024. This increase was primarily the result of a 21% increase in natural gas volumes sold and an 8% increase in natural gas prices realized. Sales of purchased natural gas primarily reflect those natural gas purchase transactions that we periodically enter into with third parties

whereby we purchase natural gas and (i) subsequently sell the natural gas to other purchasers or (ii) process the natural gas at San Mateo's cryogenic natural gas processing plants and subsequently sell the residue natural gas and NGLs to other purchasers. These revenues, and the expenses related to these transactions included in "Purchased natural gas," are presented on a gross basis in our consolidated statements of income.

Realized gain (loss) on derivatives. Our realized net gains on derivatives were $21.7 million and $12.7 million for the years ended December 31, 2025 and 2024, respectively. These realized net gains were related to natural gas basis differentials that were below the fixed prices of our natural gas basis differential swap contracts. We realized average gains on our natural gas derivatives of approximately $0.12 and $0.09 per Mcf of natural gas produced during the years ended December 31, 2025 and 2024, respectively.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $18.1 million for the year ended December 31, 2025, as compared to an unrealized gain of $13.3 million for the year ended December 31, 2024. During the year ended December 31, 2025, the aggregate net fair value of our open oil and natural gas costless collars and natural gas basis differential swap contracts changed from a net asset of approximately $16.0 million to a net asset of approximately $34.1 million, resulting in an unrealized gain on derivatives of approximately $18.1 million for the year ended December 31, 2025. During the year ended December 31, 2024, the aggregate net fair value of our open oil and natural gas derivative contracts changed from a net asset of approximately $2.7 million to a net asset of approximately $16.0 million, resulting in an unrealized gain on derivatives of approximately $13.3 million for the year ended December 31, 2024.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated.

	Year Ended December 31,		
	2025	2024	2023
(In thousands, except expenses per BOE)			
Expenses:			
Lease operating	$ 415,810	$ 325,145	$ 232,521
Transportation and processing	66,787	58,593	59,912
Midstream operating	208,142	167,400	124,021
Purchased natural gas	163,094	142,715	129,401
Depletion, depreciation and amortization	1,195,358	974,300	716,688
Taxes other than income	275,629	268,649	220,604
Accretion of asset retirement obligations	7,846	6,027	3,943
General and administrative	137,069	127,454	110,373
Total expenses	2,469,735	2,070,283	1,597,463
Operating income	1,226,542	1,434,698	1,209,322
Other income (expense):			
Net loss on asset sales and impairment	(589)	—	(202)
Interest expense	(208,520)	(171,687)	(121,520)
Other income	16,011	696	8,785
Total other expense	(193,098)	(170,991)	(112,937)
Income before income taxes	1,033,444	1,263,707	1,096,385
Income tax provision (benefit)			
Current	7,088	27,059	13,922
Deferred	165,587	265,305	172,104
Total income tax provision	172,675	292,364	186,026
Net income attributable to non-controlling interest in subsidiaries	(101,548)	(86,021)	(64,285)
Net income attributable to Matador Resources Company shareholders	$ 759,221	$ 885,322	$ 846,074
Expenses per BOE:			
Lease operating	$ 5.50	$ 5.20	$ 4.83
Transportation and processing	$ 0.88	$ 0.94	$ 1.25
Midstream operating	$ 2.75	$ 2.68	$ 2.58
Depletion, depreciation and amortization	$ 15.82	$ 15.59	$ 14.90
Taxes other than income	$ 3.65	$ 4.30	$ 4.59
General and administrative	$ 1.81	$ 2.04	$ 2.29

Year Ended December 31, 2025 as Compared to Year Ended December 31, 2024

Lease operating expenses. Our lease operating expenses increased $90.7 million, or 28%, to $415.8 million for the year ended December 31, 2025, as compared to $325.1 million for the year ended December 31, 2024. On a unit-of-production basis, our lease operating expenses increased 6% to $5.50 per BOE for the year ended December 31, 2025, as compared to $5.20 per BOE for the year ended December 31, 2024. These increases were primarily attributable to the increased number of wells being operated by us and other operators (where we own a working interest) for the year ended December 31, 2025, as compared to the year ended December 31, 2024.

Transportation and processing. Our transportation and processing expenses increased $8.2 million, or 14%, to $66.8 million for the year ended December 31, 2025, as compared to $58.6 million for the year ended December 31, 2024. This increase in transportation and processing expenses is primarily due to the 21% increase in our total oil equivalent production between the two periods. On a unit-of-production basis, our transportation and processing expenses decreased 6% to $0.88 per BOE for the year ended December 31, 2025, as compared to $0.94 per BOE for the year ended December 31, 2024. This decrease per BOE primarily resulted from the mix of revenue contracts, including from San Mateo, between the two periods.

Midstream operating. Our midstream operating expenses increased $40.7 million, or 24%, to $208.1 million for the year ended December 31, 2025, as compared to $167.4 million for the year ended December 31, 2024. This increase was primarily attributable to the expansion of the Marlan Processing Plant and increased throughput volumes from Matador's wholly-owned midstream assets, which resulted in (i) increased expenses associated with our expanded pipeline operations of $100.9 million for the year ended December 31, 2025, as compared to $73.9 million for the year ended December 31, 2024 and (ii) increased expenses associated with plant processing of $52.7 million for the year ended December 31, 2025, as compared to $34.6 million

for the year ended December 31, 2024, which was partially offset by (iii) decreased expenses associated with our commercial produced water disposal operations of $59.5 million for the year ended December 31, 2025, as compared to $63.0 million for the year ended December 31, 2024.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $221.1 million, or 23%, to $1.20 billion for the year ended December 31, 2025, as compared to $974.3 million for the year ended December 31, 2024, primarily as a result of the 21% increase in our total oil equivalent production between the respective periods. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 1% to $15.82 per BOE for the year ended December 31, 2025, as compared to $15.59 per BOE for the year ended December 31, 2024.

Taxes other than income. Our taxes other than income increased $7.0 million, or 3%, to $275.6 million for the year ended December 31, 2025, as compared to $268.6 million for the year ended December 31, 2024. This increase in taxes other than income is primarily due to the increase in oil and natural gas revenues between the two periods. On a unit-of-production basis, our taxes other than income decreased 15% to $3.65 per BOE for the year ended December 31, 2025, as compared to $4.30 per BOE for the year ended December 31, 2024. This decrease per BOE was primarily attributable to a 14% decrease in realized oil prices between the two periods.

General and administrative. Our general and administrative expenses increased $9.6 million, or 8%, to $137.1 million for the year ended December 31, 2025, as compared to $127.5 million for the year ended December 31, 2024, primarily due to increased payroll for our existing employees as well as with additional employees joining Matador to support our increased land, geoscience, drilling, completion, production, midstream and administration functions as a result of our continued growth. Our general and administrative expenses on a unit-of-production basis decreased 11% to $1.81 per BOE for the year ended December 31, 2025, as compared to $2.04 per BOE for the year ended December 31, 2024, primarily as a result of the 21% increase in our total oil equivalent production between the two periods.

Interest expense. For the year ended December 31, 2025, we incurred total interest expense of approximately $237.3 million. We capitalized approximately $28.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2025 and expensed the remaining $208.5 million to operations. For the year ended December 31, 2024, we incurred total interest expense of approximately $201.5 million. We capitalized approximately $29.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2024 and expensed the remaining $171.7 million to operations. The increase in interest expense for the year ended December 31, 2025 was primarily attributable to a $602.3 million increase in the weighted average of senior notes outstanding between the periods in connection with the Ameredev Acquisition in September 2024.

Total income tax provision. We recorded a current income tax provision of $7.1 million and a deferred income tax provision of $165.6 million for the year ended December 31, 2025. We recorded a current income tax provision of $27.1 million and a deferred income tax provision of $265.3 million for the year ended December 31, 2024. The decrease in the current income tax provision between the periods was primarily the result of the OBBBA, which made permanent, extended or modified certain provisions under the 2017 Tax Cuts and Jobs Act, among other things. The provisions of the OBBBA that are expected to most significantly impact us include (i) a permanent extension of 100% bonus depreciation for certain capital expenditures, (ii) an immediate deduction of domestic research and experimental expenditures, (iii) an acceleration of deductions for unamortized domestic research or development expenditures and (iv) an elimination of the deduction for depreciation, amortization and depletion from the definition of "adjusted taxable income" for the purpose of calculating limitations on interest expense deductions. The effective income tax rate and the total income tax provision for the year ended December 31, 2025 were not materially impacted by the enactment of the OBBBA.

Our effective income tax rate of 19% for the year ended December 31, 2025 differed from the U.S. federal statutory rate due primarily to a benefit recognized as a result of the remeasurement of deferred income taxes associated with changes in state apportionment rates following the Company's filings of its 2024 tax returns, partially offset by state taxes in New Mexico. Our effective income tax rate of 25% for the year ended December 31, 2024 differed from the U.S. federal statutory rate due primarily to state taxes in New Mexico. Our effective income tax rate excluding the effect of net income attributable to non-controlling interest in subsidiaries was 17% and 23% for the years ended December 31, 2025 and 2024, respectively, as disclosed in Note 8 to the consolidated financial statements.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue during 2026 and for the foreseeable future to be, for the acquisition, exploration and development of oil and natural gas properties and for midstream investments. We expect to fund our 2026 capital expenditures through a combination of cash on hand, operating cash flows and performance incentives paid to us by Five Point in connection with San Mateo. If capital expenditures were to exceed our operating cash flows in 2026, we expect to fund any excess capital expenditures, including for significant acquisitions, through borrowings under the Credit Agreement or the San Mateo Credit Facility (assuming availability under such facilities) or through other capital sources, including borrowings under expanded or additional credit arrangements, the sale or joint venture of midstream assets, oil and natural gas producing assets, leasehold interests or mineral interests and potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all. Our future success in growing proved reserves and production will be highly dependent on our ability to generate operating cash flows and access outside sources of capital.

At December 31, 2025, we had cash totaling $15.3 million and restricted cash totaling $64.2 million, which was primarily associated with San Mateo. By contractual agreement, the cash in the accounts held by our less-than-wholly-owned subsidiaries is not to be commingled with our other cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

At December 31, 2025, we had (i) $500.0 million of outstanding 6.875% senior notes due 2028 (the "2028 Notes"), (ii) $900.0 million of outstanding 6.500% senior notes due 2032 (the "2032 Notes"), (iii) $750.0 million of outstanding 6.250% senior notes due 2033 (the "2033 Notes"), (iv) $398.0 million of borrowings outstanding under the Credit Agreement and (v) approximately $53.8 million in outstanding letters of credit issued pursuant to the Credit Agreement.

The Credit Agreement requires us to maintain (i) a current ratio, which is defined as (x) total consolidated current assets plus the unused availability under the Credit Agreement divided by (y) total consolidated current liabilities less current maturities of debt, of not less than 1.0 at the end of each fiscal quarter and (ii) a debt to EBITDA ratio, which is defined as debt outstanding (net of up to the greater of $150 million or 10% of the elected borrowing commitments of unrestricted cash and cash equivalents) divided by a rolling four quarter EBITDA calculation, of 3.50 or less at the end of each fiscal quarter. We were in compliance with the terms of the Credit Agreement at December 31, 2025.

At December 31, 2025, San Mateo had $883.0 million in borrowings outstanding under the San Mateo Credit Facility and approximately $15.4 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility. In December 2025, San Mateo and certain of its lenders amended the San Mateo Credit Facility to (i) increase the lender commitments from $850.0 million to $1.10 billion, (ii) reduce the borrowing rate and (iii) add one new bank to San Mateo's lending group. The San Mateo Credit Facility includes an accordion feature, which provides for potential increases in lender commitments of up to $1.35 billion.

The San Mateo Credit Facility is non-recourse with respect to Matador and its other subsidiaries, but is guaranteed by San Mateo's subsidiaries and secured by substantially all of San Mateo's assets, including real property. The San Mateo Credit Facility requires San Mateo to maintain a debt to EBITDA ratio, which is defined as total consolidated funded indebtedness outstanding (as defined in the San Mateo Credit Facility) divided by a rolling four quarter EBITDA calculation, of 5.00 or less, subject to certain exceptions. The San Mateo Credit Facility also requires San Mateo to maintain an interest coverage ratio, which is defined as a rolling four quarter EBITDA calculation divided by San Mateo's consolidated interest expense for such period, of 2.50 or more. The San Mateo Credit Facility also restricts the ability of San Mateo to distribute cash to its members if San Mateo's debt to EBITDA ratio is greater than 4.50 or San Mateo's liquidity is less than 10% of the lender commitments under the San Mateo Credit Facility. San Mateo was in compliance with the terms of the San Mateo Credit Facility at December 31, 2025.

In February 2025, April 2025 and July 2025, our Board declared quarterly cash dividends of $0.3125 per share of common stock. In October 2025, the Board amended our dividend policy to increase the quarterly dividend to $0.375 per share of common stock and also declared a quarterly cash dividend of $0.375 per share of common stock. In February 2026, the Board declared a quarterly cash dividend of $0.375 per share of common stock payable on March 10, 2026 to shareholders of record as of February 27, 2026.

In April 2025, the Board approved the Share Repurchase Program authorizing the repurchase of up to $400.0 million of common stock. These repurchases may be conducted through a variety of methods including open market purchases, 10b5-1 trading plans, privately negotiated transactions or other means. The timing and number of shares that we may repurchase under the Share Repurchase Program is subject to a variety of factors, including our stock price, market conditions, trading volume and other uses for our free cash flow. There can be no assurance regarding the exact number of shares to be repurchased by us, if any. Depending on market conditions and other factors, these repurchases may be commenced or suspended at any time periodically without prior notice, and the Share Repurchase Program does not obligate us to acquire any amount of common

stock. During the year ended December 31, 2025, we repurchased 1,351,328 shares of common stock under the Share Repurchase Program at a weighted average price of $41.31 per common share for a total cost of $55.8 million.

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures in 2026. We have built significant optionality into our drilling program, which should generally allow us to decrease or increase the number of rigs we operate as necessary based on changing commodity prices and other factors. Our 2026 estimated capital expenditure budget consists of $1.35 to $1.44 billion for D/C/E capital expenditures and $100.0 to $110.0 million for midstream capital expenditures, which reflects our proportionate share of San Mateo's estimated 2026 capital expenditures as well as the estimated 2026 capital expenditures for other wholly-owned midstream projects. Substantially all of these 2026 estimated capital expenditures are expected to be allocated to (i) the further delineation and development of our leasehold position, (ii) the construction, installation and maintenance of midstream assets and (iii) our participation in certain non-operated well opportunities. Our 2026 Delaware Basin operated drilling program is expected to focus on the continued development of our various asset areas, with a continued emphasis on drilling and completing a high percentage of longer horizontal wells.

We intend to continue evaluating the opportunistic acquisition of producing properties, acreage and mineral interests and midstream assets, principally in the Delaware Basin. Purchase price multiples and per-acre prices can vary significantly based on the asset or prospect. As a result, it is difficult to estimate these capital expenditures with any degree of certainty; therefore, we have not provided estimated capital expenditures related to acquiring producing properties, acreage and mineral interests and midstream assets for 2026.

As we have done in recent years, we may divest portions of our non-core assets as well as consider monetizing other assets, such as certain midstream assets and mineral and royalty interests, as value-creating opportunities arise. Divestitures and other types of monetizations are difficult to estimate with any degree of certainty. Therefore, we have not provided estimated proceeds related to divestitures or monetizations for 2026.

Our 2026 capital expenditures may be adjusted as business conditions warrant and the amount, timing and allocation of such expenditures is largely discretionary and within our control. The aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs and scope of our midstream activities, the ability of our joint venture partners to meet their capital obligations, other opportunities that may become available to us and our ability to obtain capital. When oil or natural gas prices decline, or costs increase significantly, we have the flexibility to defer a significant portion of our capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate. A significant portion of our anticipated cash flows from operations for 2026 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin. Our existing operated and non-operated wells may not produce at the levels we are forecasting or may be temporarily shut in or restricted due to low commodity prices, and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for 2026 and the hedges we currently have in place. For a discussion of our expectations of such commodity prices, see "—General Outlook and Trends" below. At times, we use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and NGL prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. See Note 12 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2025. See "Risk Factors—Risks Related to our Financial Condition—Our exploration, development, exploitation and midstream projects require substantial capital expenditures that may exceed our cash flows from operations and potential borrowings, and we may be unable to obtain needed capital on satisfactory terms, which could adversely affect our future growth," "Risk Factors—Risks Related to our Operations—Drilling for and producing oil, natural gas and NGLs is highly speculative and involves a high degree of operational and financial risk, with many uncertainties that could adversely affect our business," "Risk Factors—Risks Related to our Operations—Our identified drilling locations are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling" and "Risk Factors—Risks Related to Laws and Regulations—Approximately 33% of our leasehold and mineral acres in the Delaware Basin is located on federal lands, which are subject to administrative permitting requirements and potential federal legislation, regulation and orders that may limit or restrict oil and natural gas operations on federal lands."

Our cash flows for the years ended December 31, 2025, 2024 and 2023 are presented below.

	Year Ended December 31,		
	2025	2024	2023
(In thousands)			
Net cash provided by operating activities	$ 2,425,015	$ 2,246,885	$ 1,867,828
Net cash used in investing activities	(2,157,682)	(3,672,114)	(3,211,192)
Net cash (used in) provided by financing activities	(282,598)	1,413,673	902,332
Net change in cash	$ (15,265)	$ (11,556)	$ (441,032)
Adjusted EBITDA attributable to Matador Resources Company shareholders[(1)]	$ 2,294,551	$ 2,298,777	$ 1,849,547

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income and net cash provided by operating activities, see "—Non-GAAP Financial Measures" below.

Net Cash Provided by Operating Activities

Net cash provided by operating activities increased by $178.1 million to $2.43 billion for the year ended December 31, 2025 from $2.25 billion for the year ended December 31, 2024. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased by $15.0 million to $2.25 billion for the year ended December 31, 2025 from $2.23 billion for the year ended December 31, 2024. This increase was primarily attributable to a 21% increase in total oil equivalent production during 2025, as compared to 2024, partially offset by lower realized oil and natural gas prices. Changes in our operating assets and liabilities between the periods resulted in a $163.1 million increase in net cash provided by operating activities for the year ended December 31, 2025, as compared to the year ended December 31, 2024.

Our operating cash flows are sensitive to a number of variables that are beyond our control and are difficult to predict. From time to time, we use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and NGL prices. For additional information on the impact of changing prices on our financial condition, see "Quantitative and Qualitative Disclosures About Market Risk." See also "Risk Factors—Risks Related to Our Financial Condition—Our success is dependent on the prices of oil, natural gas and NGLs. Low oil, natural gas and NGL prices and the continued volatility in these prices may adversely affect our financial condition and our ability to meet our capital expenditure requirements and financial obligations."

Net Cash Used in Investing Activities

Net cash used in investing activities decreased by $1.51 billion to $2.16 billion for the year ended December 31, 2025 from $3.67 billion for the year ended December 31, 2024. This decrease in net cash used in investing activities between the periods was primarily due to (i) a $1.83 billion decrease in expenditures related to the Ameredev Acquisition that occurred in September 2024, (ii) a $115.3 million decrease in expenditures related to the acquisition of oil and natural gas properties and (iii) a $10.1 million increase in cash provided by proceeds from the sale of assets. The decreases in cash used in investing activities between the periods were partially offset by (i) a $319.4 million increase in D/C/E capital expenditures primarily attributable to our operated and non-operated drilling, completion and equipping activities in the Delaware Basin, (ii) a $110.3 million decrease in proceeds from the sale of an equity method investment in the parent company of Piñon Midstream, LLC, and (iii) a $13.9 million increase in midstream capital expenditures.

Net Cash (Used in) Provided by Financing Activities

Net cash used in financing activities increased by $1.70 billion to $282.6 million for the year ended December 31, 2025, from net cash provided by financing activities of $1.41 billion for the year ended December 31, 2024. This increase in net cash used in financing activities between the periods was primarily due to (i) a $1.27 billion decrease in net proceeds from debt and equity offerings in the prior period, (ii) a $293.0 million increase in net repayments under the Credit Agreement, (iii) a $44.7 million increase in net distributions related to San Mateo, (iv) a $58.2 million increase in dividends paid and (v) a $55.8 million increase in repurchases of common stock. These increases in net cash used in financing activities were partially offset by (i) a $175.0 million increase in net borrowings under the San Mateo Credit Facility and (ii) a $31.0 million decrease in costs to amend credit facilities.

See Note 7 to the consolidated financial statements in this Annual Report for a summary of our debt, including the Credit Agreement, the San Mateo Credit Facility, the 2028 Notes, the 2032 Notes and the 2033 Notes.

Non-GAAP Financial Measures

We define Adjusted EBITDA attributable to Matador shareholders ("Adjusted EBITDA") as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, non-recurring transaction costs for certain acquisitions, certain other non-cash items and non-cash stock-based compensation expense and net gain or loss on asset sales and impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as a primary indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities, respectively.

	Year Ended December 31,		
	2025	2024	2023
(In thousands)			
Unaudited Adjusted EBITDA Reconciliation to Net Income:			
Net income attributable to Matador Resources Company shareholders	$ 759,221	$ 885,322	$ 846,074
Net income attributable to non-controlling interest in subsidiaries	101,548	86,021	64,285
Net income	860,769	971,343	910,359
Interest expense	208,520	171,687	121,520
Total income tax provision	172,675	292,364	186,026
Depletion, depreciation and amortization	1,195,358	974,300	716,688
Accretion of asset retirement obligations	7,846	6,027	3,943
Unrealized (gain) loss on derivatives	(18,084)	(13,299)	1,261
Non-cash stock-based compensation expense	18,327	14,982	13,661
Net loss on impairment	589	—	202
(Income) expense related to contingent consideration and other	(7,338)	5,420	(6,038)
Consolidated Adjusted EBITDA	2,438,662	2,422,824	1,947,622
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(144,111)	(124,047)	(98,075)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$ 2,294,551	$ 2,298,777	$ 1,849,547

	Year Ended December 31,		
	2025	2024	2023
(In thousands)			
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:			
Net cash provided by operating activities	$ 2,425,015	$ 2,246,885	$ 1,867,828
Net change in operating assets and liabilities	(176,189)	(13,080)	(50,027)
Interest expense, net of non-cash portion	193,756	155,154	114,473
Current income tax provision	7,088	27,059	13,922
Net loss on asset sales and impairment	589	—	—
Other non-cash and non-recurring (income) expense	(11,597)	6,806	1,426
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(144,111)	(124,047)	(98,075)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$ 2,294,551	$ 2,298,777	$ 1,849,547

For the year ended December 31, 2025, we reported net income attributable to Matador shareholders of $759.2 million, as compared to $885.3 million for the year ended December 31, 2024. This decrease primarily resulted from (i) a $221.1 million increase in depletion, depreciation and amortization expenses, (ii) a $90.7 million increase in lease operating expenses, (iii) a $40.7 million increase in midstream operating expenses, (iv) a $36.8 million increase in interest expense, (v) an $8.2 million increase in transportation and processing expenses and (vi) lower realized oil and natural gas prices for the year ended December 31, 2025, as compared to the year ended December 31, 2024. These expense increases were partially offset by (i) increased oil and natural gas production and (ii) a $119.7 million decrease in the income tax provision for the year ended December 31, 2025, as compared to the year ended December 31, 2024.

Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2025, the material off-balance sheet arrangements and transactions that we have entered into include (i) non-operated drilling commitments, (ii) firm gathering, transportation, processing, fractionation, sales and disposal commitments and (iii) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, transportation and disposal commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See "—Obligations and Commitments" below and Note 14 to the consolidated financial statements in this Annual Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at December 31, 2025.

	Payments Due by Period				
(In thousands)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Contractual Obligations:					
Borrowings, including letters of credit[1]	$ 1,350,244	$ —	$ —	$ 1,350,244	$ —
Senior unsecured notes[2]	2,150,000	—	500,000	—	1,650,000
Office leases	101,390	3,542	12,339	13,091	72,418
Non-operated drilling commitments[3]	79,038	79,038	—	—	—
Drilling rig contracts[4]	22,622	22,622	—	—	—
Asset retirement obligations[5]	150,372	6,309	6,785	1,720	135,558
Transportation, gathering, processing and disposal agreements with non-affiliates[6]	2,320,113	144,567	582,695	452,288	1,140,563
Transportation, gathering, processing and disposal agreements with San Mateo[7]	743,907	56,812	279,080	206,590	201,425
Midstream contracts	11,638	11,638	—	—	—
Total contractual cash obligations	$ 6,929,324	$ 324,528	$ 1,380,899	$ 2,023,933	$ 3,199,964

(1) The amounts included in the table above represent principal maturities only. At December 31, 2025, we had $398.0 million in borrowings outstanding under the Credit Agreement and approximately $53.8 million in outstanding letters of credit issued pursuant to the Credit Agreement. The outstanding borrowings under the Credit Agreement mature on March 22, 2029. At December 31, 2025, San Mateo had $883.0 million of borrowings outstanding under the San Mateo Credit Facility and approximately $15.4 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility. The outstanding borrowings under the San Mateo Credit Facility mature on November 26, 2029. Assuming the amounts outstanding and interest rates of 5.63% and 5.72%, respectively, for the Credit Agreement and the San Mateo Credit Facility at December 31, 2025, the interest expense for such facilities is expected to be approximately $22.4 million and $50.5 million, respectively, each year until maturity.

(2) The amounts included in the table above represent principal maturities only. Interest expense on the $500.0 million of outstanding 2028 Notes as of December 31, 2025 is expected to be approximately $34.4 million each year until maturity. Interest expense on the $900.0 million of outstanding 2032 Notes as of December 31, 2025 is expected to be approximately $58.5 million each year until maturity. Interest expense on the $750.0 million of outstanding 2033 Notes as of December 31, 2025 is expected to be approximately $46.9 million each year until maturity.

(3) At December 31, 2025, we had outstanding commitments to participate in the drilling and completion of various non-operated wells.

(4) We do not own or operate our own drilling rigs, but instead we enter into contracts with third parties for such drilling rigs. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

(5) The amounts included in the table above represent discounted cash flow estimates for future asset retirement obligations at December 31, 2025.

(6) From time to time, we enter into agreements with third parties whereby we commit to deliver anticipated natural gas and oil production and produced water from certain portions of our acreage for transportation, gathering, processing, fractionation, sales and disposal. Certain of these agreements contain minimum volume commitments, including contracts related to firm transportation on Energy Transfer's Hugh Brinson Pipeline. If we do not meet the minimum volume commitments under these agreements, we would be required to pay deficiency fees. See Note 14 to the consolidated financial statements in this Annual Report for more information about these contractual commitments.

(7) We dedicated to San Mateo our current and certain future leasehold interests in the Rustler Breaks asset area and the Wolf portion of the West Texas asset area and acreage in the Greater Stebbins Area and Stateline asset area pursuant to 15-year, fixed-fee oil transportation, oil, natural gas and produced water gathering and produced water disposal agreements. In addition, we dedicated to San Mateo our current and certain future leasehold interests in the Rustler Breaks asset area and acreage in the Greater Stebbins Area and Stateline asset area pursuant to 15-year, fixed-fee natural gas processing agreements. In connection with the Pronto Transaction, we dedicated to San Mateo our current and certain future leasehold interests in the Ranger and Antelope Ridge asset areas pursuant to 15-year, fixed fee natural gas gathering, compression, treating and processing agreements with San Mateo whereby San Mateo will gather, compress, treat and process natural gas produced from our operated wells in northern Lea County, New Mexico. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

General Outlook and Trends

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. For example, the current administration and Congress have altered, and may continue to alter, our current regulatory framework and may impact our business and the oil and natural gas industry generally. Commodity price volatility, in particular, is a significant risk to our business, cash flows and results of operations. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, ongoing military conflicts, including the ongoing military conflicts between Russia and Ukraine and in the Middle East, political instability, particularly in China and in the Middle East, the actions of OPEC+, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors.

The prices we receive for oil, natural gas and NGLs heavily influence our revenues, profitability, cash flow available for capital expenditures, the repayment of debt, the payment of cash dividends, if any, the repurchase of our common stock, if any, access to capital, borrowing capacity under our Credit Agreement and future rate of growth. Oil, natural gas and NGL prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and NGLs have been volatile, and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or NGL prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and NGLs we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves and our ability to comply with the financial covenants under our Credit Agreement. See "Risk Factors—Risks Related to our Financial Condition—Our success is dependent on the prices of oil, natural gas and NGLs. Low oil, natural gas and NGL prices and the continued volatility in these prices may adversely affect our financial condition and our ability to meet our capital expenditure requirements and financial obligations."

For the year ended December 31, 2025, oil prices averaged $64.73 per Bbl, as compared to $75.76 per Bbl in 2024, ranging from a high of $80.04 per Bbl in mid-January to a low of $55.27 per Bbl in mid-December, based upon the WTI oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $64.99 per Bbl (with no realized gains or losses from oil derivatives) for our oil production for the year ended December 31, 2025, as compared to $75.89 per Bbl (with no realized gains or losses from oil derivatives) for the year ended December 31, 2024. At February 24, 2026, the WTI oil futures contract price for the earliest delivery date had increased from year-end 2025, closing at $65.63 per Bbl, but was lower compared to $70.70 per Bbl on February 24, 2025.

For the year ended December 31, 2025, natural gas prices averaged $3.62 per MMBtu, as compared to $2.40 per MMBtu in 2024, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. During 2025, natural gas prices ranged from a low of $2.70 per MMBtu in late August to a high of $5.29 per MMBtu in early December. We report production volumes in two streams, oil and natural gas (which includes both dry gas and NGLs). NGL prices were also lower in 2025 as compared to 2024, which contributed to lower realized weighted average natural gas prices for the year ended December 31, 2025. We realized a weighted average natural gas price of $2.08 per Mcf ($2.20 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the year ended December 31, 2025, as compared to $2.38 per Mcf ($2.47 per Mcf including realized losses from natural gas derivatives) for the year ended December 31, 2024. At February 24, 2026, the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date had decreased from year-end 2025, closing at $2.92 per MMBtu, and was lower as compared to $3.99 per MMBtu at February 24, 2025.

The prices we receive for oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the WTI oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. At December 31, 2025, most of our oil production from the Delaware Basin was sold based on prices established in Midland, Texas, and a significant portion of our natural gas production from the Delaware Basin was sold based on Houston Ship Channel pricing, while the remainder of our Delaware Basin natural gas production was sold primarily based on prices established at the Waha hub in far West Texas.

The Midland-Cushing (Oklahoma) oil price differential has been highly volatile in recent years. At February 24, 2026, this oil price differential was approximately +$0.66 per Bbl. At February 24, 2026, we had no derivative contracts in place to mitigate our exposure to this Midland-Cushing (Oklahoma) oil price differential for 2026.

Certain volumes of our Delaware Basin natural gas production are exposed to the Waha-Henry Hub basis differential, which has also been highly volatile in recent years. In recent years, concerns about natural gas pipeline takeaway capacity out of the Delaware Basin began to increase and a result, the Waha-Henry Hub basis differential began to widen. The Waha-Henry Hub basis differential averaged ($2.96) per MMBtu for the year ended December 31, 2025. Between December 31, 2025 and February 24, 2026, this natural gas price differential remained wide at approximately ($5.11) per MMBtu. A significant portion of our Delaware Basin natural gas production, however, is sold at Houston Ship Channel pricing and is not exposed to Waha pricing. At certain times, we may also sell a portion of our natural gas production into other markets to improve our realized natural gas pricing. For example, in the fourth quarter of 2025, the Company entered into an agreement to transport natural gas on Energy Transfer's Hugh Brinson Pipeline. The Hugh Brinson Pipeline is expected to provide direct access from the Waha hub in the Permian Basin to Henry Hub markets along the Louisiana Gulf Coast. Further, approximately 4% of our reported natural gas production for the year ended December 31, 2025 was attributable to the Haynesville shale play, which is not exposed to Waha pricing. In addition, most of our natural gas volumes in the Delaware Basin are processed for NGLs, resulting in a further reduction in the reported natural gas volumes exposed to Waha pricing.

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and NGL prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and NGL prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under the Credit Agreement and through the capital markets. During the year ended December 31, 2025, we realized gains on our natural gas basis differential derivative contracts of approximately $21.7 million resulting primarily from natural gas basis differentials that were below the fixed prices of our natural gas basis differential swap contracts.

We have at times, including in the fourth quarter of 2025, experienced pipeline-related interruptions to our oil, natural gas or NGL production or produced water disposal. In certain recent periods, shortages of NGL fractionation capacity were experienced by certain operators in the Delaware Basin. Although we did not encounter such fractionation capacity problems, we can provide no assurances that such problems will not arise. If we do experience any material interruptions with produced water disposal, takeaway capacity or NGL fractionation, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected. Should we experience future periods of negative pricing for natural gas as we have experienced historically, including in 2024 and 2025, we may again temporarily shut in certain high gas-oil ratio wells and take other actions to mitigate the impact on our realized natural gas prices and results.

We have at times experienced inflation in the costs of certain oilfield services, materials and equipment, including diesel, steel, labor, trucking, sand, personnel and completion costs, among others. Should oil prices increase, we may be subject to additional service cost inflation in future periods, which may increase our costs to drill, complete, equip and operate wells. In addition, supply chain disruptions, tariffs and trade restrictions and other inflationary pressures experienced in recent periods throughout the United States and global economy and in the oil and natural gas industry may limit our ability to procure the necessary products and services we need for drilling, completing and producing wells in a timely and cost-effective manner, which could result in reduced margins and delays to our operations and could, in turn, adversely affect our business, financial condition, results of operations and cash flows. See "Risk Factors—Risks Related to our Financial Condition—Our industry and the broader U.S. economy have experienced higher than expected inflationary pressures in recent years. Should these conditions persist, it may impact our ability to procure services, materials and equipment on a cost-effective basis, or at all, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected" and "Risk Factors—Risks Related to Laws and Regulations—Changes in U.S. foreign trade policies, including the imposition of additional tariffs and other trade barriers, and efforts to withdraw from or materially modify international trade agreements, may materially and adversely affect our business, operations and financial condition."

Our oil and natural gas exploration, development, production, midstream and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial monetary penalties or delay or suspension of operations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are proposed or promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. For more information about the Company's regulatory matters, see "Business—Regulation" and "Risk Factors—Risks Related to Laws and Regulations".

Certain segments of the investor community have at times expressed negative sentiment towards investing in the oil and natural gas industry and some investors, including certain pension funds, sovereign wealth funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social

and environmental considerations. See "Risk Factors—Risks Related to our Common Stock—Attention to ESG and conservation matters and a negative shift in market perception towards the oil and natural gas industry could adversely affect demand for oil and natural gas and our stock price."

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells will experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and NGL price declines, however, drilling additional oil or natural gas wells may not be economic, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A significant reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and the availability under our Credit Agreement. See "Risk Factors—Risks Related to our Financial Condition—Our exploration, development, exploitation and midstream projects require substantial capital expenditures that may exceed our cash flows from operations and potential borrowings, and we may be unable to obtain needed capital on satisfactory terms, which could adversely affect our future growth".

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable and that the actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates. We consider the following to be our most critical accounting policies and estimates involving significant judgment or estimates by our management. See Note 2 to the consolidated financial statements in this Annual Report for further details on our accounting policies at December 31, 2025.

Oil and Natural Gas Properties

We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities.

Capitalized costs of oil and natural gas properties are depleted using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the depletable base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the depletable base. Exploratory dry holes are included in the depletable base immediately upon the determination that the well is not productive.

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) any income tax effects related to the properties involved.

Any excess of our net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. Our derivative instruments are not considered in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Our engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the applicable rules allow us to disclose proved, probable and possible reserves, we have elected to present only proved reserves in this Annual Report. The applicable rules define proved reserves as the 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.

Our engineers and technical staff must make many subjective assumptions based on their professional judgment in developing reserves estimates. Reserves estimates are updated quarterly and consider recent production levels and other technical information about each well. Estimating oil and natural gas reserves is complex and inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations can vary. The process also requires certain economic assumptions, including assumptions related to oil and natural gas prices, development expenditures, operating expenses, capital expenditures, taxes and availability of funds. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas will most likely vary from our estimates. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect our future reserves estimates, financial condition, results of operations and cash flows. We cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in an impairment of assets that may be material. See "Risk Factors—Risks Related to our Financial Condition—Our oil and natural gas reserves are estimated and may not reflect the actual volumes of oil and natural gas we will recover, and significant inaccuracies in these reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves" and "Risk Factors—Risks Related to our Financial Condition—We may be required to write down the carrying value of our proved properties under accounting rules, and these write-downs could adversely affect our financial condition."

Estimates of proved oil and natural gas reserves are key inputs used for the calculations of depletion, the ceiling test and the fair value assigned to proved oil and natural gas reserves acquired in a business combination. The estimated present value of future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. The associated commodity prices and the applicable discount rate used to determine the fair value assigned to proved oil and natural gas reserves acquired in a business combination are based upon a variety of factors on the date of acquisition. The associated commodity prices and the applicable discount rate used in estimates for depletion and the ceiling test are in accordance with guidelines established by the SEC. Under these guidelines, future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state taxing authorities. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and tax carryforwards. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Purchase Accounting

Periodically we acquire assets and assume liabilities in transactions accounted for as business combinations, such as the Advance Acquisition in 2023 and the Ameredev Acquisition in 2024.

In estimating the fair value of assets acquired and liabilities assumed in these transactions, including the Advance Acquisition and the Ameredev Acquisition, we must make a number of estimates and assumptions and may engage third-party valuation experts. The most significant assumptions relate to the estimated fair values of oil and natural gas properties. Significant judgments and assumptions are inherent in these estimates and include, among other things, estimates of future production volumes, estimates of future commodity prices, expected development and operating costs, an estimate of a market-based weighted average cost of capital rate and recent market comparable transactions for unproved acreage.

Recent Accounting Pronouncements

See Note 2 to the consolidated financial statements in this Annual Report for a description of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative financial instruments, but we do not enter into derivative financial instruments for trading purposes.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and NGLs fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our anticipated future production.

We typically use costless (or zero-cost) collars, three-way collars and/or swap contracts to manage risks related to changes in oil, natural gas and NGL prices. Costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. Three-way costless collars also provide us with downside price protection through the purchase of a put option, but they also allow us to participate in price upside through the purchase of a call option. The purchase of both the put option and call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially "costless" to us. In the case of a costless collar, the put option or options and the call option or options have different fixed price components. When the settlement price is below the price floor established by the collar, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil, natural gas or NGL volume. When the settlement price is above the price ceiling established by the costless collar, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil, natural gas or NGL volume. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

We record all derivative financial instruments at fair value, which is determined using purchase and sale information available for similarly traded securities. Additionally, we have considered the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

At December 31, 2025, we had various costless collar contracts open and in place to mitigate our exposure to oil price volatility, each with an established price floor and ceiling. At December 31, 2025, we had natural gas basis differential swap contracts open and in place to mitigate our exposure to natural gas price volatility, with a specific term (calculation period), notional quantity (volume hedged) and fixed price. We had no open contracts associated with NGL prices at December 31, 2025.

See Note 12 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2025. Such information is incorporated herein by reference.

Effect of Derivatives Legislation. The Dodd-Frank Act, among other things, established federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when, or if, this will be accomplished. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements.

In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. See "Risk Factors—Risks Related to Laws and Regulations—Derivatives legislation adopted by Congress could have an adverse impact on our ability to hedge risks associated with our business."

Interest rate risk. We do not and have not used interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense on existing debt. At December 31, 2025, we had $398.0 million of outstanding borrowings under our Credit Agreement at an interest rate of 5.63%, $500.0 million of outstanding 2028 Notes at a coupon rate of 6.875%, $900.0 million of outstanding 2032 Notes at a coupon rate of 6.500%, $750.0 million of outstanding 2033 Notes at a coupon rate of 6.250% and $883.0 million of outstanding borrowings under the San Mateo Credit Facility at an interest rate of 5.72%. If we incur additional indebtedness in the future and at higher interest rates, we may use interest rate derivatives. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers and San Mateo is subject to the credit risk of their customers. The inability or failure of our or San Mateo's significant customers to meet their obligations or their insolvency or liquidation may adversely affect our financial condition, results of operations and cash flows. In addition, our derivative arrangements expose us to credit risk in the event of nonperformance by our counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation requires us to conduct the due diligence necessary to determine credit terms and credit limits, which may include (i) reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, its historical payment record and the financial ability of its parent company to make payment if the customer cannot and (ii) undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our derivative financial instruments in place at February 24, 2026 were Bank of America, PNC Bank, Truist Bank, The Bank of Nova Scotia, Royal Bank of Canada, Comerica Bank, BOKF (or affiliates thereof), The Toronto Dominion Bank, J.P. Morgan Chase Bank and Wells Fargo Bank, which are all lenders under our Credit Agreement.

Impact of inflation. Although inflation in the U.S. softened in 2024 and 2025, prices for many services, materials and equipment have remained elevated relative to pre-2022 levels. We do not know how long these inflationary pressures may persist or the impact they may have on our business moving forward. We tend to specifically experience inflationary pressure on the cost of oilfield services and equipment with increases in oil and natural gas prices and with increases in drilling activity in our areas of operations, including the Wolfcamp and Bone Spring plays in the Delaware Basin and the Haynesville shale play. See "Risk Factors—Risks Related to our Financial Condition—Our industry and the broader U.S. economy have experienced higher than expected inflationary pressures in recent years related to increases in oil and natural gas prices, continued supply chain disruptions, labor shortages and geopolitical instability, among other pressures. Should these conditions persist, it may impact our ability to procure services, materials and equipment on a cost-effective basis, or at all, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected" and "Risk Factors—Risks Related to our Operations—The unavailability or high cost of drilling rigs, completion equipment and services, supplies and personnel, including hydraulic fracturing equipment and personnel, could adversely affect our ability to establish and execute exploration and development plans within budget and on a timely basis, which could have a material adverse effect on our financial condition, results of operations and cash flows."

Item 8. Financial Statements and Supplementary Data.

Our financial statements appear at the end of this Annual Report beginning on page F-1.

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

Not applicable.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Annual Report, we evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2025 to ensure that (i) information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in

the SEC's rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2025, there were no changes in our internal controls that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report based on the framework in 2013 "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG, our independent registered public accounting firm, has issued an attestation report on our controls over financial reporting as of December 31, 2025 as included herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Matador Resources Company:

Opinion on Internal Control Over Financial Reporting

We have audited Matador Resources Company 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 income, changes in 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 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

Item 9B. Other Information.

During the three months ended December 31, 2025, no director or officer (as defined in Rule 16a-1(f) under the Exchange Act) of the Company adopted, modified or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement for our 2026 Annual Meeting of Shareholders to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report (our "Definitive Proxy Statement"). Such responsive information is expected to be included under the captions "Proposal 1—Election of Directors," "Corporate Governance," "Executive Compensation" and "Director Compensation."

Item 11. Executive Compensation.

The information required in response to this Item 11 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Executive Compensation."

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

Equity Compensation Plan Information

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2025.

Equity Compensation Plan Information

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders[1][2]	1,297,593	$ —	6,739,067
Equity compensation plans not approved by security holders	—	—	—
Total	1,297,593	$ —	6,739,067

(1) The Matador Resources Company 2019 Long-Term Incentive Plan (the "2019 Incentive Plan") was adopted by our Board in April 2019 and approved by our shareholders on June 6, 2019. For a description of our 2019 Incentive Plan, see Note 9 to the consolidated financial statements in this Annual Report.

(2) The Matador Resources Company 2022 Employee Stock Purchase Plan (the "ESPP") was adopted by our Board in April 2022 and approved by our shareholders on June 10, 2022. For a description of our ESPP, see Note 9 to the consolidated financial statements in this Annual Report.

Other information required in response to this Item 12 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Security Ownership of Certain Beneficial Owners and Management."

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

The information required in response to this Item 13 is incorporated herein by reference to our Definitive Proxy Statement under the captions "Transactions with Related Persons" and "Corporate Governance—Independence of Directors."

Item 14. Principal Accounting Fees and Services.

The information required in response to this Item 14 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Proposal 3—Ratification of Appointment of KPMG LLP."

PART IV

Item 15. Exhibits and Financial Statement Schedules.

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

1. Index to Consolidated Financial Statements, Report of Independent Registered Public Accounting Firm, Consolidated Balance Sheets as of December 31, 2025 and 2024, Consolidated Statements of Income for the Years Ended December 31, 2025, 2024 and 2023, Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2025, 2024 and 2023 and Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024 and 2023.

2. *Financial Statement Schedules*: All other schedules for which provision is made in the applicable accounting regulations of the SEC are omitted because the required information is either not applicable, not required or is shown in the respective financial statements or in the notes thereto.

3. *Exhibits*: The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index included below.

Item 16. Form 10-K Summary.

None.

EXHIBIT INDEX

Exhibit Number	Description
2.1*	Securities Purchase Agreement, dated January 24, 2023, by and among MRC Hat Mesa, LLC, MRC Energy Company (solely for the limited purposes stated therein), AEP EnCap HoldCo, LLC, Ameradvance Management LLC and Advance Energy Partners Holdings, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 24, 2023).
2.2	Amendment No. 1 to Securities Purchase Agreement, dated April 5, 2023, by and among MRC Hat Mesa, LLC, AEP EnCap HoldCo, LLC, Ameradvance Management LLC and Advance Energy Partners Holdings, LLC (incorporated by reference to Exhibit 2.2 to the Annual Report on Form 10-K for the year ended December 31, 2023).
2.3*	Waiver and Release Agreement and Amendment No. 2 to Securities Purchase Agreement, dated December 1, 2023, by and among MRC Hat Mesa, LLC, AEP EnCap HoldCo, LLC, Ameradvance Management LLC and Advance Energy Partners Holdings, LLC (incorporated by reference to Exhibit 2.3 to the Annual Report on Form 10-K for the year ended December 31, 2023.).
2.4*	Securities Purchase Agreement, dated June 12, 2024, by and among MRC Toro, LLC, MRC Energy Company (solely for the limited purposes stated therein), Ameredev II Parent, LLC, Ameredev Intermediate II, LLC and Ameredev Stateline II, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on June 12, 2024).
2.5*	Amendment No. 1 to Securities Purchase Agreement, dated August 29, 2024, by and among MRC Toro, LLC, Ameredev II Parent, LLC, Ameredev Intermediate II, LLC and Ameredev Stateline II, LLC (incorporated by reference to Exhibit 2.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2024).
2.6	Amendment No. 2 to Securities Purchase Agreement, dated February 14, 2025, by and among MRC Toro, LLC, Ameredev II Parent, LLC, Ameredev Intermediate II, LLC (incorporated by reference to Exhibit 2.6 to the Annual Report on Form 10-K for the year ended December 31, 2024).
3.1	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company dated April 2, 2015 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company effective June 2, 2017 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.4	Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 22, 2018).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1 filed on January 19, 2012).
4.2	Indenture, dated as of April 11, 2023, by and among Matador Resources Company, the subsidiary guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 11, 2023).
4.3	First Supplemental Indenture, dated as of July 25, 2023, by and among Matador Resources Company, MRC Hat Mesa, LLC, the subsidiary guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2023).
4.4	Indenture, dated as of April 2, 2024, by and among Matador Resources Company, the subsidiary guarantors party thereto and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 2, 2024).
4.5	First Supplemental Indenture, dated as of September 20, 2024, by and among MRC Toro, LLC, the subsidiary guarantors party thereto and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2024).
4.6	Second Supplemental Indenture, dated as of September 20, 2024, by and among MRC Toro, LLC, the subsidiary guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2024).

4.7	Indenture, dated as of September 25, 2024, by and among Matador Resources Company, the subsidiary guarantors party thereto and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on September 25, 2024).
4.8	First Supplemental Indenture, dated as of March 18, 2025, by and among Matador Resources Company, MRC Royalties, LLC, the existing subsidiary guarantors and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
4.9	Second Supplemental Indenture, dated as of March 18, 2025, by and among Matador Resources Company, MRC Royalties, LLC, the existing subsidiary guarantors and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
4.10	Third Supplemental Indenture, dated as of March 18, 2025, by and among Matador Resources Company, MRC Royalties, LLC, the existing subsidiary guarantors and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
4.11	Description of Capital Stock (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2019).
10.1†	Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.2†	First Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.3†	Second Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to the Registration Statement on Form S-1 filed on December 30, 2011).
10.4†	Form of Employment Agreement between Matador Resources Company and Van H. Singleton, II, effective February 5, 2015 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2014).
10.5†	Form of Employment Agreement between Matador Resources Company and G. Gregg Krug, effective February 19, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.6†	First Amendment to the Employment Agreement between Matador Resources Company and G. Gregg Krug (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.7†	Form of Employment Agreement between Matador Resources Company and Michael D. Frenzel (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2022).
10.8†	Form of Employment Agreement between Matador Resources Company and each of Christopher P. Calvert, W. Thomas Elsener, Bryan A. Erman, Robert T. Macalik and Glenn W. Stetson (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2024).
10.9†	Advisor Agreement between MRC Energy Company and G. Gregg Krug, effective February 28, 2026 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 23, 2026).
10.10†	Form of Indemnification Agreement between Matador Resources Company and each of the directors and executive officers thereof (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.11	Second Amended and Restated Pledge and Security Agreement, by and among MRC Energy Company, Longwood Gathering and Disposal Systems GP, Inc. and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.12	Second Amended, Restated and Consolidated Unconditional Guaranty, by and among MRC Permian Company, MRC Rockies Company, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., Longwood Gathering and Disposal Systems, LP, Matador Resources Company and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2012).

10.13	Fourth Amended and Restated Credit Agreement, dated as of November 18, 2021, by and among MRC Energy Company, as Borrower, the Lending Entities from time to time parties thereto, as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 18, 2021).
10.14	First Amendment to Fourth Amended and Restated Credit Agreement dated as of April 25, 2022, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2022).
10.15	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of March 31, 2023, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, Royal Bank of Canada, as resigning Administrative Agent, and Truist Bank, as successor Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on April 3, 2023).
10.16	Third Amendment to Fourth Amended and Restated Credit Agreement, dated as of April 10, 2023, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and Truist Bank, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).
10.17	Fourth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 19, 2023, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and Truist Bank, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 19, 2023).
10.18	Fifth Amendment to Fourth Amended and Restated Credit Agreement, dated as of March 22, 2024, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and PNC Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 25, 2024).
10.19	Sixth Amendment to Fourth Amended and Restated Credit Agreement, dated as of September 18, 2024, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and PNC Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on September 19, 2024).
10.20	Seventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of December 9, 2025, by and among MRC Energy Company, as Borrower, the lending entities parties thereto as Lenders, and PNC Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 9, 2025).
10.21†	Matador Resources Company Nonqualified Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.59 to the Annual Report on Form 10-K for the year ended December 31, 2015).
10.22†	Matador Resources Company Annual Cash Incentive Plan, effective as of January 1, 2019 (incorporated by reference to Exhibit 10.66 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.23†	Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on June 11, 2015).
10.24†	Amendment Number One to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.25†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2015).
10.26†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2015).
10.27†	Form of Restricted Stock Unit Award Agreement for deferred delivery relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.63 to the Annual Report on Form 10-K for the year ended December 31, 2016).
10.28†	Form of Restricted Stock Unit Award Agreement for Annual Grants with delayed delivery relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).

10.29†	Form of Restricted Stock Unit Award Agreement for director awards with deferred delivery under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.30†	Form of Nonqualified Stock Option Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.31†	Form of Nonqualified Stock Option Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.32†	Form of Restricted Stock Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.33†	Form of Restricted Stock Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.34†	Form of Phantom Unit Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.67 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.35†	Form of Performance Stock Unit Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.68 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.36†	Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Registration Statement on Form S-8 filed on June 6, 2019).
10.37†	First Amendment to Matador Resources Company 2019 Long-Term Incentive Plan effective April 21, 2022 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 16, 2022).
10.38†	Form of Restricted Stock Unit Award Agreement for director awards under the Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.39†	Form of Restricted Stock Unit Award Agreement for director awards with deferred delivery under the Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.40†	Form of Phantom Unit Award Agreement for awards under the Matador Resources Company 2019 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2020).
10.41†	Form of Performance Stock Unit Award Agreement for awards under the Matador Resources Company 2019 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2020).
10.42†	Form of Performance Stock Unit Award Agreement for awards under the Matador Resources Company 2019 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.58 to the Annual Report on Form 10-K for the year ended December 31, 2021).
10.43†	Form of Performance Stock Unit Award Agreement for awards under the Matador Resources Company 2019 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.59 to the Annual Report on Form 10-K for the year ended December 31, 2021).
10.44†	Form of Restricted Stock Award Agreement for awards under the Matador Resources Company 2019 Long-Term Incentive Plan with ratable vesting for employees without employment agreements (incorporated by reference to Exhibit 10.60 to the Annual Report on Form 10-K for the year ended December 31, 2021).
10.45†	Form of Stock Option Cancellation Agreement for certain stock options under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K for the year ended December 31, 2020).
10.46†	Matador Resources Company 2022 Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on June 16, 2022).
19.1	Matador Resources Company Insider Trading Policy (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (filed herewith).

23.1	Consent of KPMG LLP (filed herewith).
23.2	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
97	Matador Resources Company Clawback Policy (incorporated by reference to Exhibit 97 to the Annual Report on Form 10-K for the year ended December 31, 2023).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company's Annual Report on Form 10-K for the year ended December 31, 2025, formatted in Inline XBRL (Inline eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Changes in Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements (submitted electronically herewith).
104	Cover Page Interactive Data File, formatted in Inline XBRL (included as Exhibit 101).

†	Indicates a management contract or compensatory plan or arrangement.
*	This filing excludes certain schedules and exhibits pursuant to Item 601(a)(5) of Regulation S-K, which the Company agrees to furnish supplementally to the SEC upon request; provided, however, that the Company may request confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended, for any schedules or exhibits so furnished.

SIGNATURES

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

MATADOR RESOURCES COMPANY

February 26, 2026

By: /s/ Joseph Wm. Foran
Joseph Wm. Foran
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Joseph Wm. Foran Joseph Wm. Foran	Chairman and Chief Executive Officer (Principal Executive Officer)	February 26, 2026
/s/ Robert T. Macalik Robert T. Macalik	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2026
/s/ Benjamin T. Colodney Benjamin T. Colodney	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2026
/s/ Shelley F. Appel Shelley F. Appel	Director	February 26, 2026
/s/ Reynald A. Baribault Reynald A. Baribault	Director	February 26, 2026
/s/ R. Gaines Baty R. Gaines Baty	Director	February 26, 2026
/s/ William M. Byerley William M. Byerley	Director	February 26, 2026
/s/ Monika U. Ehrman Monika U. Ehrman	Director	February 26, 2026
/s/ Paul W. Harvey Paul W. Harvey	Director	February 26, 2026
/s/ Timothy E. Parker Timothy E. Parker	Director	February 26, 2026
/s/ Kenneth L. Stewart Kenneth L. Stewart	Director	February 26, 2026
/s/ Susan M. Ward Susan M. Ward	Director	February 26, 2026

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report.

Batch drilling. The process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to crude oil, other liquid hydrocarbons or produced water.

Bcf. One billion cubic feet of natural gas.

Bench. A geologic zone or formation or a subdivision of a geologic formation.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or NGLs to six Mcf of natural gas.

BOE/d. BOE per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Central delivery point or CDP. The point on an oil, natural gas or produced water system where such product is aggregated from one or more gathering or transportation pipelines, wells, tank batteries or leases. Custody is often transferred to a third party at a central delivery point.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

Conventional reservoirs or resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Coring. The act of taking a core. A core is a solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation. It is common practice to take cores from wells in the process of being drilled. A core bit is attached to the end of the drill pipe. The core bit then cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or natural gas, and its characteristics (porosity, permeability, etc.) are determined.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

Developed oil and natural gas reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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. The difference between a particular oil or natural gas price and the applicable benchmark price, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price.

Dry hole. A well found to be incapable of producing hydrocarbons.

Economically producible. As it relates to a resource, a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

ESP. Electric submersible pump.

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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Extension well. A well drilled to extend the limits of a known reservoir.

Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the

assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farmin" while the interest transferred by the assignor is a "farmout."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

GAAP, or U.S. GAAP. United States, generally accepted accounting principles.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Hydraulic fracturing. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to prop the channel open, so that fluids or gases may more easily flow from the formation, through the fracture channel and into the wellbore. This technique may also be referred to as fracture stimulation.

Lateral length. Length of the drilled or completed portion of a horizontal well.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane, pentane and natural gasoline resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a natural gas processing facility.

MBbl. One thousand barrels of crude oil, other liquid hydrocarbons or produced water.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells.

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, natural gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Organization of Petroleum Exporting Countries or OPEC. An intergovernmental group of 12 of the world's major oil-exporting countries, which was founded in 1960 to coordinate the petroleum policies of its members and to provide member countries with technical and economic aid.

OPEC+. A loose affiliation of the member countries of OPEC and 11 of the world's other major oil-exporting countries, including Russia.

Overriding royalty interest. A fractional interest in the gross production of oil and natural gas under a lease, in addition to the usual royalties paid to the lessor, free of any expense for exploration, drilling, development, operating, marketing and other costs incident to the production and sale of oil and natural gas produced from the lease. It is an interest carved out of the lessee's working interest, as distinguished from the lessor's reserved royalty interest.

Pad. The surface constructed to accommodate the drilling, completion and production operations of an oil or natural gas well.

Pad drilling. The process by which multiple horizontal wells are drilled from a single pad. In pad drilling, each well on the pad is drilled to total depth before the next well is initiated.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recovered than probable reserves.

Probable reserves. Additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Producing well, or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well's production exceed production-related expenses and taxes.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining such wells and related equipment and facilities.

Properties. Natural gas and oil wells, production and related equipment and facilities and oil, natural gas, or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Prospectivity. Having the potential for the discovery and/or future development of commercial hydrocarbons in a specific geographic area or formation.

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

Proved developed non-producing. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but non-producing reserves.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved properties. Properties with proved reserves.

Proved reserves. The 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.

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

Reasonable certainty. A high degree of confidence that the quantities of oil and/or natural gas will be recovered.

Recompletion. Completing in the same wellbore to reach a new reservoir after production from the original reservoir has been abandoned.

Repeatability. The potential ability to drill multiple wells within a prospect or trend.

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.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

Royalty interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

2-D seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflection seismic data collected along a single source profile.

3-D seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

Simul-Frac (Simultaneous Fracturing). Simul-Frac is a hydraulic fracturing technique in which two wells are fractured simultaneously using one hydraulic fracturing fleet. This differs from traditional zipper-frac where only one well is hydraulically stimulated.

Spud. The act of beginning to drill an oil or natural gas well.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to specific geologic condition.

Tcf. One trillion cubic feet of natural gas.

Throughput. The volume of product transported or passing through a pipeline, plant or other facility.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Trimul-Frac (Triple Simultaneous Fracturing). Trimul-Frac is an advanced hydraulic fracturing technique where three wells are fractured simultaneously using one hydraulic fracturing fleet. While similar to Simul-Frac in terms of treating multiple wells simultaneously, Trimul-Frac stimulates three wells versus two.

Unconventional resource play. A set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (i) low-permeability sandstone and shale formations and (ii) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.

Unproved and unevaluated properties. Properties where no drilling or other actions have been undertaken that permit such properties to be classified as proved and to which no proved reserves have been assigned.

Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.

Visualization. An exploration technique in which the size and shape of subsurface features are mapped and analyzed based upon information derived from well logs, seismic data and other well information.

Volumetric reserves analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.

WTI. West Texas Intermediate.

Wellbore. The hole made by a well.

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

Matador Resources Company and Subsidiaries

CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2025, 2024 and 2023

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Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Matador Resources Company:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Matador Resources Company and subsidiaries (the Company) as of December 31, 2025 and 2024, the related consolidated statements of income, changes in 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 Matters

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.

Impact of estimated proved oil and natural gas reserves related to evaluated oil and natural gas properties on depletion expense and the ceiling test calculation

As discussed in Note 2 to the consolidated financial statements, the Company uses the full-cost method of accounting for its investments in oil and natural gas properties and amortizes capitalized costs of oil and natural gas properties using the unit-of-production method based on production and estimates of proved reserves quantities. The Company is required to perform a ceiling test calculation on a quarterly basis and the applicable ceiling is equal to the sum of (1) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus (2) unproved and unevaluated property costs not being amortized, plus (3) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (4) any income tax effects related to the properties involved. Any excess of the Company's net capitalized costs above the cost center ceiling is charged to operations as a full-cost ceiling impairment. Estimates of economically recoverable oil and natural gas reserves depend upon a number of factors and assumptions, including quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the operating costs incurred, the amount of future development expenditures, and the price received for the production.

For the year ended December 31, 2025, the Company recorded depletion expense of evaluated oil and natural gas properties of $1.1 billion. Additionally, as discussed in Note 3 to the consolidated financial statements, the Company's consolidated balance sheet includes $14.3 billion of gross evaluated oil and natural gas properties as of December 31, 2025. The Company's internal reservoir engineers prepare an estimate of the proved oil and natural gas reserves, and the Company engages external reservoir engineers to independently evaluate the proved oil and natural gas reserves estimated by the Company.

We identified the assessment of the impact of estimated proved oil and natural gas reserves related to evaluated oil and natural gas properties on both depletion expense and the ceiling test calculation as a critical audit matter. There is a high degree of subjectivity in evaluating the estimate of proved oil and natural gas reserves as auditor judgment was required to evaluate the assumptions used by the Company related to future production volumes, development costs, operating costs, and forecasted oil and natural gas prices inclusive of price differentials.

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 over the Company's depletion and ceiling test processes. This included controls related to the development of the assumptions listed above used to estimate proved reserves used in the respective calculations. We evaluated (1) the professional qualifications of the Company's internal reservoir engineers as well as the external reservoir engineers and external engineering firm, (2) the knowledge, skill, and ability of the Company's internal and external reservoir engineers, and (3) the relationship of the external reservoir engineers and external 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 also compared the pricing assumptions, including price differentials, used in the reservoir engineers' estimate of the proved reserves to publicly available oil and natural gas pricing data. We evaluated assumptions used in the reservoir engineers' estimate regarding future operating and development costs based on historical actual results. In addition, we compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast and compared the forecasted production assumption used by the Company in the current period to historical production. We read the findings of the Company's external reservoir engineers in connection with our evaluation of the Company's reserves estimates. We recalculated the depletion expense calculation and analyzed it for compliance with industry and regulatory standards. We also analyzed the ceiling test impairment calculation for compliance with industry and regulatory standards. In addition, we performed an independent calculation of the ceiling test impairment calculation and compared our results with the Company's results.

/s/ KPMG LLP

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

Dallas, Texas
February 26, 2026

Matador Resources Company and Subsidiaries

CONSOLIDATED BALANCE SHEETS
(In thousands, except par value and share data)

	December 31,	
	2025	**2024**
ASSETS		
Current assets		
Cash	$ 15,314	$ 23,033
Restricted cash	64,163	71,709
Accounts receivable		
Oil and natural gas revenues	286,158	331,590
Joint interest billings	140,043	260,555
Other	103,628	62,584
Derivative instruments	34,052	15,968
Lease and well equipment inventory	43,842	38,469
Prepaid expenses and other current assets	129,368	123,437
Total current assets	816,568	927,345
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	14,286,726	12,534,290
Unproved and unevaluated	1,823,456	1,702,203
Midstream properties	1,963,059	1,683,334
Other property and equipment	53,199	47,532
Less accumulated depletion, depreciation and amortization	(7,395,142)	(6,203,263)
Net property and equipment	10,731,298	9,764,096
Other assets		
Other long-term assets	162,703	158,668
Total assets	$ 11,710,569	$ 10,850,109
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 540,620	$ 619,167
Royalties payable	351,062	227,865
Advances from joint interest owners	64,169	83,338
Other current liabilities	75,658	64,987
Total current liabilities	1,031,509	995,357
Long-term liabilities		
Borrowings under Credit Agreement	398,000	595,500
Borrowings under San Mateo Credit Facility	883,000	615,000
Senior unsecured notes payable	2,121,102	2,114,908
Asset retirement obligations	144,063	114,237
Deferred income taxes	1,015,931	847,666
Other long-term liabilities	120,312	110,009
Total long-term liabilities	4,682,408	4,397,320
Commitments and contingencies (Note 14)		
Shareholders' equity		
Common stock — $0.01 par value, 160,000,000 shares authorized; 124,409,739 and 125,101,268 shares issued; and 124,262,322 and 125,048,396 shares outstanding, respectively	1,244	1,251
Additional paid-in capital	2,509,118	2,533,247
Retained earnings	3,153,112	2,556,987
Treasury stock, at cost, 147,417 and 52,872 shares, respectively	(5,333)	(2,336)
Total Matador Resources Company shareholders' equity	5,658,141	5,089,149
Non-controlling interest in subsidiaries	338,511	368,283
Total shareholders' equity	5,996,652	5,457,432
Total liabilities and shareholders' equity	$ 11,710,569	$ 10,850,109

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

Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31,		
	2025	**2024**	**2023**
Revenues			
Oil and natural gas revenues	$ 3,238,750	$ 3,143,834	$ 2,545,599
Third-party midstream services revenues	164,733	141,027	122,153
Sales of purchased natural gas	253,031	194,097	149,869
Realized gain (loss) on derivatives	21,679	12,724	(9,575)
Unrealized gain (loss) on derivatives	18,084	13,299	(1,261)
Total revenues	3,696,277	3,504,981	2,806,785
Expenses			
Lease operating	415,810	325,145	232,521
Transportation and processing	66,787	58,593	59,912
Midstream operating	208,142	167,400	124,021
Purchased natural gas	163,094	142,715	129,401
Depletion, depreciation and amortization	1,195,358	974,300	716,688
Taxes other than income	275,629	268,649	220,604
Accretion of asset retirement obligations	7,846	6,027	3,943
General and administrative	137,069	127,454	110,373
Total expenses	2,469,735	2,070,283	1,597,463
Operating income	1,226,542	1,434,698	1,209,322
Other income (expense)			
Net loss on asset sales and impairment	(589)	—	(202)
Interest expense	(208,520)	(171,687)	(121,520)
Other income	16,011	696	8,785
Total other expense	(193,098)	(170,991)	(112,937)
Income before income taxes	1,033,444	1,263,707	1,096,385
Income tax provision (benefit)			
Current	7,088	27,059	13,922
Deferred	165,587	265,305	172,104
Total income tax provision	172,675	292,364	186,026
Net income	860,769	971,343	910,359
Net income attributable to non-controlling interest in subsidiaries	(101,548)	(86,021)	(64,285)
Net income attributable to Matador Resources Company shareholders	$ 759,221	$ 885,322	$ 846,074
Earnings per common share			
Basic	$ 6.10	$ 7.16	$ 7.10
Diluted	$ 6.09	$ 7.14	$ 7.05
Weighted average common shares outstanding			
Basic	124,556	123,568	119,139
Diluted	124,586	124,076	119,980

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

Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(In thousands)

For the Years Ended December 31, 2025, 2024 and 2023

	Common Stock		Additional paid-in capital	Retained earnings	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount			Shares	Amount			
Balance at January 1, 2023	118,953	1,190	2,101,999	1,007,642	5	(34)	3,110,797	206,294	3,317,091
Dividends declared ($0.65 per share)	—	—	—	(77,175)	—	—	(77,175)	—	(77,175)
Issuance of stock pursuant to incentive and purchase plans, net of shares withheld for taxes	656	6	(15,511)	—	146	(5,087)	(20,592)	—	(20,592)
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	21,580	—	—	—	21,580	—	21,580
Contribution related to formation of San Mateo, net of tax of $8.0 million (See Note 11)	—	—	30,178	—	—	—	30,178	—	30,178
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	24,500	24,500
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(78,253)	(78,253)
Cancellation of treasury stock	(131)	(2)	(5,074)	—	(131)	5,076	—	—	—
Current period net income	—	—	—	846,074	—	—	846,074	64,285	910,359
Balance at December 31, 2023	119,478	$ 1,194	$2,133,172	$ 1,776,541	20	$ (45)	$ 3,910,862	$ 216,826	$ 4,127,688
Dividends declared ($0.85 per share)	—	—	—	(104,876)	—	—	(104,876)	—	(104,876)
Issuance of stock pursuant to incentive and purchase plans, net of shares withheld for taxes	455	4	(9,205)	—	115	(5,319)	(14,520)	—	(14,520)
Issuance of common stock pursuant to public offering	5,250	53	344,610	—	—	—	344,663	—	344,663
Cost to issue equity	—	—	(2,566)	—	—	—	(2,566)	—	(2,566)
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	23,749	—	—	—	23,749	—	23,749
Contribution of Pronto to San Mateo (See Note 11)	—	—	27,713	—	—	—	27,713	143,787	171,500
Contributions related to formation of San Mateo, net of tax of $5.0 million (See Note 11)	—	—	18,802	—	—	—	18,802	—	18,802
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	19,110	19,110
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(97,461)	(97,461)
Cancellation of treasury stock	(82)	—	(3,028)	—	(82)	3,028	—	—	—
Current period net income	—	—	—	885,322	—	—	885,322	86,021	971,343
Balance at December 31, 2024	125,101	$ 1,251	$2,533,247	$ 2,556,987	53	$(2,336)	$ 5,089,149	$ 368,283	$ 5,457,432

	Common Stock		Additional paid-in capital	Retained earnings	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount			Shares	Amount			
Balance at January 1, 2025	125,101	$ 1,251	$2,533,247	$ 2,556,987	53	$(2,336)	$ 5,089,149	$ 368,283	$ 5,457,432
Dividends declared ($1.3125 per share)	—	—	—	(163,096)	—	—	(163,096)	—	(163,096)
Issuance of stock pursuant to incentive and purchase plans, net of shares withheld for taxes	693	7	(5,364)	—	127	(3,970)	(9,327)	—	(9,327)
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	28,332	—	—	—	28,332	—	28,332
Contributions related to formation of San Mateo, net of tax of $2.7 million (See Note 11)	—	—	10,270	—	—	—	10,270	—	10,270
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(131,320)	(131,320)
Cancellation of treasury stock	(1,384)	(14)	(57,367)	—	(1,384)	57,381	—	—	—
Repurchases of common stock	—	—	—	—	1,351	(56,408)	(56,408)	—	(56,408)
Current period net income	—	—	—	759,221	—	—	759,221	101,548	860,769
Balance at December 31, 2025	124,410	$ 1,244	$2,509,118	$ 3,153,112	147	$(5,333)	$ 5,658,141	$ 338,511	$ 5,996,652

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

Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2025	2024	2023
Operating activities			
Net income	$ 860,769	$ 971,343	$ 910,359
Adjustments to reconcile net income to net cash provided by operating activities			
Depletion, depreciation and amortization	1,195,358	974,300	716,688
Deferred income tax provision	165,587	265,305	172,104
Stock-based compensation expense	18,327	14,982	13,661
Unrealized (gain) loss on derivatives	(18,084)	(13,299)	1,261
Amortization of debt issuance cost and other debt related costs	14,764	16,533	7,047
Accretion of asset retirement obligations	7,846	6,027	3,943
Other non-cash changes	4,259	(1,386)	(7,262)
Changes in operating assets and liabilities			
Accounts receivable, prepaid expenses and other current assets	114,285	(138,137)	48,136
Lease and well equipment inventory	(35,313)	(10,934)	(3,034)
Other long-term assets	(10)	4,052	646
Accounts payable, accrued liabilities and other current liabilities	(8,930)	33,748	2,810
Royalties payable	123,196	56,193	34,273
Advances from joint interest owners	(19,170)	63,384	(32,402)
Other long-term liabilities	2,131	4,774	(402)
Net cash provided by operating activities	2,425,015	2,246,885	1,867,828
Investing activities			
Drilling, completion and equipping capital expenditures	(1,542,253)	(1,222,831)	(1,192,800)
Acquisition of oil and natural gas properties	(339,126)	(454,443)	(187,655)
Midstream capital expenditures	(297,746)	(283,881)	(165,719)
Expenditures for other property and equipment	(4,246)	(5,691)	(3,636)
Proceeds from sale of assets and other	22,426	12,370	14,750
Proceeds from sale of equity method investment	3,263	113,576	—
Acquisition of Ameredev	—	(1,831,214)	—
Acquisition of Advance	—	—	(1,676,132)
Net cash used in investing activities	(2,157,682)	(3,672,114)	(3,211,192)
Financing activities			
Repayments of borrowings under Credit Agreement	(2,367,500)	(3,969,500)	(3,032,000)
Borrowings under Credit Agreement	2,170,000	4,065,000	3,532,000
Repayments of borrowings under San Mateo Credit Facility	(345,000)	(733,000)	(171,000)
Borrowings under San Mateo Credit Facility	613,000	826,000	228,000
Cost to enter into or amend credit facilities	(2,406)	(33,436)	(9,296)
Dividends paid	(163,096)	(104,876)	(77,175)
Repurchases of common stock	(55,849)	—	—
Contributions related to formation of San Mateo	13,000	23,800	38,200
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(131,320)	(97,461)	(78,253)
Taxes paid related to net share settlement of stock-based compensation	(11,960)	(16,956)	(22,910)
Proceeds from issuance of senior unsecured notes	—	1,650,000	494,800
Purchase of senior unsecured notes	—	(699,191)	—
Issuance costs of senior unsecured notes	—	(28,157)	(8,503)
Proceeds from issuance of common stock	—	344,663	—
Contribution related to Pronto Transaction	—	171,500	—
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	19,110	24,500
Other	(1,467)	(3,823)	(16,031)
Net cash (used in) provided by financing activities	(282,598)	1,413,673	902,332
Decrease in cash and restricted cash	(15,265)	(11,556)	(441,032)
Cash and restricted cash at beginning of period	94,742	106,298	547,330
Cash and restricted cash at end of period	$ 79,477	$ 94,742	$ 106,298

Supplemental disclosures of cash flow information (Note 15)

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

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also has operations in the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, the Company conducts midstream operations primarily through its midstream joint venture, San Mateo Midstream, LLC and its subsidiaries ("San Mateo") in support of, and to provide flow assurance for, the Company's exploration, development and production operations, and San Mateo provides natural gas processing, oil transportation services, oil, natural gas and produced water gathering services and produced water disposal services to third parties.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Matador and its wholly-owned and majority-owned subsidiaries. These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). Accordingly, the Company consolidates certain subsidiaries and joint ventures that are less-than-wholly-owned and are not involved in oil and natural gas exploration, including San Mateo, and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification ("ASC") Topic 810, *Consolidation*. The Company proportionately consolidates certain joint ventures that are less-than-wholly-owned and are involved in oil and natural gas exploration. All intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications

Certain reclassifications to captions within the consolidated balance sheets, statements of income and statements of changes in shareholders' equity have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's consolidated financial statements are based on a number of significant estimates, including oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative instruments, deferred tax assets and liabilities, purchase price allocations and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates in the purchase price allocations and of asset retirement obligations and certain tax accruals. The Company's oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors that are beyond the Company's control, including oil and natural gas prices, are prepared by the Company's engineering staff in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Restricted Cash

Restricted cash represents a portion of the cash associated with the Company's less-than-wholly-owned subsidiaries, primarily San Mateo. By contractual agreement, the cash in the accounts held by the Company's less-than-wholly-owned subsidiaries is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Accounts Receivable

The Company sells its operated oil, natural gas and natural gas liquids ("NGL") production to various purchasers (see "—Revenues" below). In addition, the Company may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of the Company's accounts receivable are due from purchasers of oil, natural gas and NGLs, participants in oil and natural gas wells for which the Company serves as the operator, customers of San Mateo or the Company's derivative counterparties. Accounts receivable are typically due within 30 to 60 days of the production date and 30 days of the billing date and are stated at amounts due from purchasers and industry partners. Amounts are considered past due if they have been outstanding for 60 days or more. No interest is typically charged on past due amounts.

The Company reviews its need for an allowance for doubtful accounts on a periodic basis and determines the allowance, if any, by considering the length of time past due, previous loss history, future net revenues associated with the debtor's ownership interest in oil and natural gas properties operated by the Company and the debtor's ability to pay its obligations, among other things. The Company has no allowance for doubtful accounts related to its accounts receivable for any reporting period presented.

For the years ended December 31, 2025, 2024 and 2023, three significant purchasers accounted for 72%, 79% and 76%, respectively, of the Company's total oil, natural gas and NGL revenues: Plains Marketing, L.P. (49%, 53% and 42%, respectively), Exxon Mobil Corporation (13%, 15% and 24%, respectively) and Enterprise Products Partners L.P. (10%, 11% and 10%, respectively). If any one of Matador's major customers were to stop purchasing its production, the Company believes there are a number of other purchasers to whom the Company could sell Matador's production. If multiple significant customers were to discontinue purchasing Matador's production abruptly, the Company believes it would have the resources needed to access alternative customers or markets and avoid or materially mitigate associated sales disruptions. At December 31, 2025, 2024 and 2023, approximately 32%, 32% and 38%, respectively, of the Company's accounts receivable, including joint interest billings, related to the top three purchasers.

Lease and Well Equipment Inventory

Lease and well equipment inventory is stated at the lower of cost or net realizable value and consists entirely of materials or equipment scheduled for use in future well or midstream operations.

Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $71.7 million, $66.6 million and $54.2 million of its general and administrative costs into oil and natural gas properties in 2025, 2024 and 2023, respectively. The Company capitalized $21.2 million, $17.5 million and $20.2 million of its interest expense into oil and natural gas properties for the years ended December 31, 2025, 2024 and 2023, respectively.

Capitalized costs of oil and natural gas properties are depleted using the unit-of-production method based upon production and estimates of proved reserves quantities. For the years ended December 31, 2025, 2024 and 2023, the Company recorded depletion expense of $1.13 billion, $925.6 million and $672.0 million, respectively. Unproved and unevaluated property costs are excluded from the depletable base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the depletable base. Exploratory dry holes are included in the depletable base immediately upon determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) any income tax effects related to the properties involved.

Any excess of the Company's net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The Company's derivative instruments are not considered in the ceiling test computations as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost changes in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues. For the period from January through December 2025, these average oil and natural gas prices were $61.82 per Bbl and $3.39 per MMBtu, respectively. For the period from January through December 2024, these average oil and natural gas prices were $71.96 per Bbl and $2.13 per MMBtu, respectively. For the period from January through December 2023, these average oil and natural gas prices were $74.70 per Bbl and $2.64 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation and marketing fees and regional price differentials.

During the years ended December 31, 2025, 2024 and 2023, the Company's full-cost ceiling exceeded the net capitalized costs less related deferred income taxes. As a result, the Company recorded no impairment to its net capitalized costs during the years ended December 31, 2025, 2024 and 2023. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Midstream Properties and Other Property and Equipment

Midstream properties and other property and equipment are recorded at historical cost or acquisition date fair value and include midstream equipment and facilities, including the Company's pipelines, processing facilities and produced water disposal systems, and corporate assets, including furniture, fixtures, equipment, land and leasehold improvements. Midstream equipment and facilities are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful lives or the term of the lease. Software, furniture, fixtures and other equipment are depreciated over their useful life (five to 30 years) using the straight-line method. The Company capitalized $3.5 million, $3.4 million and $2.9 million of general and administrative costs into midstream properties in 2025, 2024 and 2023, respectively. The Company capitalized $7.6 million, $12.2 million and $2.1 million of interest expense into midstream properties for the years ended December 31, 2025, 2024 and 2023, respectively. Maintenance and repair costs that do not extend the useful life of the property or equipment are expensed as incurred. See Note 3 for a detail of midstream properties and other property and equipment.

The Company evaluates midstream properties and other property and equipment for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Expected future cash flows represent management's estimates based on reasonable and supportable assumptions.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Gains and losses associated with the disposition of midstream properties and other property and equipment are recognized as a component of other income (expense) in the consolidated statements of income.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties, midstream properties or other property and equipment on the consolidated balance sheets. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in the consolidated statements of income.

Derivative Financial Instruments

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and NGL prices. The Company's derivative financial instruments are recorded on the consolidated balance sheets as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments, and as a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of income. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Realized gains and losses from the settlement of derivative financial instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled derivative financial instruments are reported as a component of revenues in the consolidated statements of income. See Note 12 for additional information about the Company's derivative instruments.

Revenues

The Company enters into contracts with customers to sell its oil and natural gas production. Revenue from these contracts is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under oil and natural gas marketing contracts is typically received from the purchaser one to two months after production.

The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead or a central delivery point, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing, which price is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred at or after the transfer of control of the oil, the differentials are included in oil revenues on the statements of income, as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in transportation and processing expenses on the Company's consolidated statements of income, as they represent payment for services performed outside of the contract with the customer.

The Company's natural gas is sold at the lease location, at the inlet or outlet of a natural gas processing plant or at an interconnect near a marketing hub following transportation from a processing plant. The majority of the Company's natural gas is sold under fee-based contracts. When the natural gas is sold at the lease, the purchaser gathers the natural gas via pipeline to natural gas processing plants where, if necessary, NGLs are extracted. The NGLs and remaining residue natural gas are then sold by the purchaser, or if the Company elects to take in-kind the natural gas or the NGLs, the Company sells the natural gas or the NGLs to a third party. Under the fee-based contracts, the Company receives NGL and residue natural gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the gathering and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those services, revenue is recognized on a gross basis, and the related costs are included in transportation and processing expenses on the Company's consolidated statements of income.

The Company recognizes midstream services revenues at the time services have been rendered and the price is fixed and determinable. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues related to the Company's

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

working interest are eliminated in consolidation. Since the Company has a right to payment from its customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, the Company applies the practical expedient in ASC Topic 606, *Revenue from Contracts with Customers* that allows recognition of revenue in the amount for which there is a right to invoice the customer without estimating a transaction price for each contract and allocating that transaction price to the performance obligations within each contract.

The Company periodically enters into natural gas purchase transactions with third parties whereby the Company (i) purchases the third party's natural gas and subsequently sells the natural gas to other purchasers or (ii) processes the third party's natural gas at San Mateo's Marlan cryogenic natural gas processing plant in Eddy County, New Mexico (the "Marlan Processing Plant") or Black River cryogenic natural gas processing plant in Eddy County, New Mexico (the "Black River Processing Plant") and then purchases, and subsequently sells, the residue natural gas and NGLs to other purchasers. Revenues and expenses from these transactions are presented on a gross basis on the Company's consolidated statements of income as the Company acts as a principal in the transactions by assuming the risk and rewards of ownership, including credit risk, of the natural gas purchased and by assuming the responsibility to deliver and process the natural gas volumes to be sold.

The following table summarizes the Company's total revenues and revenues from contracts with customers on a disaggregated basis for the years ended December 31, 2025, 2024 and 2023 (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Revenues from contracts with customers	$ 3,656,514	$ 3,478,958	$ 2,817,621
Realized gain (loss) on derivatives	21,679	12,724	(9,575)
Unrealized gain (loss) on derivatives	18,084	13,299	(1,261)
Total revenues	$ 3,696,277	$ 3,504,981	$ 2,806,785

	Year Ended December 31,		
	2025	2024	2023
Oil revenues	$ 2,840,167	$ 2,772,360	$ 2,144,894
Natural gas revenues	398,583	371,474	400,705
Third-party midstream services revenues	164,733	141,027	122,153
Sales of purchased natural gas	253,031	194,097	149,869
Total revenues from contracts with customers	$ 3,656,514	$ 3,478,958	$ 2,817,621

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Stock-Based Compensation

The Company may grant equity-based and liability-based common stock, stock options, restricted stock, restricted stock units, performance stock units and other awards permitted under any long-term incentive plan of the Company then in effect to members of its Board of Directors (the "Board") and certain employees, contractors and advisors. All equity-based awards are measured at fair value on the date of grant and are recognized on a straight-line basis over the awards' vesting periods as either a component of general and administrative expenses in the consolidated statements of income or capitalized in accordance with the Company's policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration, development and midstream activities. Awards that are expected to be settled in cash are liability-based awards, which are measured at fair value at each reporting date and are recognized over the awards' vesting periods either as a component of general and administrative expenses in the consolidated statements of income or capitalized in accordance with the Company's

policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration, development and midstream activities.

The Company uses the Monte Carlo simulation method to measure the fair value of performance units. The closing price of Matador's common stock on the trading day prior to the grant date is used to measure the fair value of restricted stock and restricted stock unit awards granted under the 2019 Long-Term Incentive Plan (the "2019 Incentive Plan").

The Company's consolidated statements of income for the years ended December 31, 2025, 2024 and 2023 include equity-based compensation (non-cash) expense of $18.3 million, $15.0 million and $13.7 million, respectively. This equity-based compensation expense includes common stock awards granted to employees and restricted stock units paid to independent members of the Board and advisors as compensation for their services to the Company totaling $1.7 million, $1.3 million and $1.2 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability approach for financial accounting and reporting. The Company evaluates the probability of realizing the future benefits of its deferred tax assets and records a valuation allowance for the portion of any deferred tax assets for which it is more likely than not that the benefit from the deferred tax asset will not be realized.

The Company recognizes tax benefits from an uncertain tax position on the basis of a two-step process in which (i) the Company determines whether it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based upon the technical merits of the position and (ii) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of tax benefit that is more than 50% likely to be realized upon ultimate settlement with the related tax authority.

When necessary, the Company would include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on its consolidated statements of income. The Company did not record any interest or penalties related to income taxes for the years ended December 31, 2025, 2024 and 2023.

Allocation of Purchase Price in Business Combinations

As part of the Company's business strategy, it periodically pursues the acquisition of midstream assets and oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Earnings Per Common Share

The Company reports basic earnings attributable to Matador Resources Company shareholders per common share, which excludes the effect of potentially dilutive securities, and diluted earnings attributable to Matador Resources Company shareholders per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted earnings per common share as reported for the years ended December 31, 2025, 2024 and 2023 (in thousands, except per share data).

	Year Ended December 31,		
	2025	2024	2023
Net income attributable to Matador Resources Company shareholders — numerator	$ 759,221	$ 885,322	$ 846,074
Weighted average common shares outstanding — denominator			
Basic	124,556	123,568	119,139
Dilutive effect of options and restricted stock units	30	508	841
Diluted weighted average common shares outstanding	124,586	124,076	119,980
Earnings per common share attributable to Matador Resources Company shareholders			
Basic	$ 6.10	$ 7.16	$ 7.10
Diluted	$ 6.09	$ 7.14	$ 7.05

Credit Risk

The Company's cash is held in financial institutions and at times these amounts exceed the insurance limits of the Federal Deposit Insurance Corporation. Management believes, however, that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

The Company uses derivative financial instruments to mitigate its exposure to oil, natural gas and NGL price volatility. These transactions expose the Company to potential credit risk from its counterparties. The Company manages counterparty credit risk through established internal derivatives policies that are reviewed on an ongoing basis. Additionally, the Company's commodity derivative contracts at December 31, 2025 were all with lenders under the Company's reserves-based revolving credit agreement (the "Credit Agreement").

Accounts receivable constitute the principal component of additional credit risk to which the Company may be exposed. The Company attempts to minimize credit risk exposure to counterparties by monitoring the financial condition and payment history of its purchasers and joint interest partners.

Recent Accounting Pronouncements

Income Taxes. In December 2023, the Financial Accounting Standards Board ("FASB") issued ASU 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*, which is intended to enhance the transparency and decision usefulness of income tax disclosures. The amendments in this standard provide for enhanced income tax information primarily through changes to the rate reconciliation and income taxes paid. This ASU is effective for the Company prospectively to all annual periods beginning after December 15, 2024, with retrospective application permitted. The Company retrospectively adopted this standard in the current period and the changes are reflected in Note 8 of the consolidated financial statements in this Annual Report. While the adoption of this ASU modified the Company's disclosures, it did not have an impact on the Company's consolidated balance sheets, consolidated statements of income or consolidated statements of cash flows.

Disaggregation of Income Statement Expenses. In November 2024, the FASB issued ASU 2024-03, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*. The amendments in this update require disclosure in the Company's annual and interim consolidated financial statements of specified information about certain costs and expenses, including depreciation, depletion and amortization recognized as part of oil and gas producing activities and employee compensation. This ASU is effective for the Company to all annual periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. While the adoption of this ASU will modify the Company's disclosures, it will not have an impact on the Company's consolidated balance sheets, consolidated statements of income or consolidated statements of cash flows.

NOTE 3 — PROPERTY AND EQUIPMENT

The following table presents a summary of the Company's property and equipment balances as of December 31, 2025 and 2024 (in thousands).

	December 31,	
	2025	2024
Oil and natural gas properties		
Evaluated (subject to depletion)	$ 14,286,726	$ 12,534,290
Unproved and unevaluated (not subject to depletion)	1,823,456	1,702,203
Total oil and natural gas properties	16,110,182	14,236,493
Accumulated depletion	(7,093,268)	(5,959,845)
Net oil and natural gas properties	9,016,914	8,276,648
Midstream properties		
Midstream equipment and facilities	1,963,059	1,683,334
Accumulated depreciation	(264,938)	(211,048)
Net midstream properties	1,698,121	1,472,286
Other property and equipment		
Furniture, fixtures and other equipment	22,810	20,007
Software	8,361	8,283
Leasehold improvements	22,028	19,242
Total other property and equipment	53,199	47,532
Accumulated depreciation	(36,936)	(32,370)
Net other property and equipment	16,263	15,162
Net property and equipment	$ 10,731,298	$ 9,764,096

The following table provides a breakdown of the Company's unproved and unevaluated property costs not subject to depletion as of December 31, 2025 and the year in which these costs were incurred (in thousands).

Description	2025	2024	2023	2022	2021 and prior	Total
Costs incurred for						
Property acquisition	$ 255,126	$ 585,463	$ 321,062	$ 95,880	$ 420,481	$ 1,678,012
Exploration wells	12,560	2,313	846	164	1,011	16,894
Development wells	125,988	1,604	738	156	64	128,550
Total	$ 393,674	$ 589,380	$ 322,646	$ 96,200	$ 421,556	$ 1,823,456

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Property acquisition costs are transferred into the depletable base on an ongoing basis as these properties are evaluated and proved reserves are established or impairment is determined. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions.

Property acquisition costs incurred that remain in unproved and unevaluated property at December 31, 2025 are related to the Company's leasehold and mineral acquisitions in the Delaware Basin in Southeast New Mexico and West Texas. These costs are associated with acreage for which proved reserves have yet to be assigned. A significant portion of these costs are associated with properties that are held by production or have automatic lease renewal options. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the depletable base.

Costs excluded from depletion also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the depletable base on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $145.4 million at December 31, 2025, of which $16.9 million was associated with exploration wells and $128.6 million was associated with development wells. The

NOTE 3 — PROPERTY AND EQUIPMENT — Continued

Company anticipates that most of the costs associated with these wells in progress at December 31, 2025 will be transferred to the depletable base during 2026. Unproved and unevaluated property costs for exploration and development wells incurred in years prior to 2025 are costs related to the advanced preparation for wells that the Company intends to drill in the future.

NOTE 4 — LEASES

The Company determines if an arrangement is a lease at inception of the contract. If an arrangement is a lease, the present value of the related lease payments is recorded as a liability, and an equal amount is capitalized on the Company's consolidated balance sheets. The Company elected to include payments for non-lease components associated with certain leases when determining the present value of the lease payments. Right of use assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. The Company's estimated incremental borrowing rate, determined at the lease commencement date using the Company's average secured borrowing rate, is used to calculate present value. The weighted average estimated incremental borrowing rates used for the year ended December 31, 2025 were 5.40% and 6.15% for operating leases and finance leases, respectively. For these purposes, the lease term includes options to extend the lease when it is reasonably certain that the Company will exercise such option. Leases with terms of 12 months or less at inception are not recorded on the consolidated balance sheets unless there is a significant cost to terminate the lease, including the cost of removal of the leased asset. As the Company is the responsible party under these arrangements, the Company records the resulting assets and liabilities on a gross basis in its consolidated balance sheets.

The following table presents supplemental consolidated statements of income information related to lease expenses, on a gross basis, for the years ended December 31, 2025 and 2024, respectively (in thousands). Lease payments represent gross payments to vendors, which, for certain of the Company's operating assets, are partially offset by amounts received from other working interest owners in the Company's operated wells.

	Year Ended December 31,	
	2025	2024
Operating leases		
Lease operating	$ 35,407	$ 30,141
General and administrative	5,189	2,910
Total operating leases[1]	40,596	33,051
Short-term leases		
Lease operating	68,277	46,770
Midstream operating	8,933	11,110
General and administrative	22	54
Total short-term leases[2][3]	77,232	57,934
Finance leases		
Depreciation of assets	1,765	2,296
Interest on lease liabilities	866	607
Total finance leases	2,631	2,903
Total lease expense	$ 120,459	$ 93,888

(1) Does not include gross payments related to drilling rig leases of $84.7 million and $87.8 million for the years ended December 31, 2025 and 2024, respectively, that were capitalized and recorded in "Oil and natural gas properties, full-cost method" in the consolidated balance sheets at December 31, 2025 and 2024, respectively.

(2) These costs are related to leases that are not recorded as right of use assets or lease liabilities in the consolidated balance sheets as they are short-term leases.

(3) Does not include gross payments related to short-term drilling rig leases and other equipment rentals of $265.9 million and $231.8 million for the years ended December 31, 2025 and 2024, respectively, that were capitalized and recorded in "Oil and natural gas properties, full-cost method" in the consolidated balance sheets at December 31, 2025 and 2024, respectively.

NOTE 4 — LEASES — Continued

The following table presents supplemental consolidated balance sheet information related to leases as of December 31, 2025 and 2024, respectively (in thousands).

	December 31,	
	2025	2024
Operating leases		
Other long-term assets	$ 138,655	$ 127,445
Other current liabilities	$ (65,091)	$ (57,924)
Other long-term liabilities	(79,190)	(72,498)
Total operating lease liabilities	$ (144,281)	$ (130,422)
Finance leases		
Other property and equipment, at cost	$ 14,204	$ 12,783
Accumulated depreciation	(11,297)	(9,532)
Net property and equipment	$ 2,907	$ 3,251
Other current liabilities	$ (1,113)	$ (1,312)
Other long-term liabilities	(1,175)	(1,021)
Total finance lease liabilities	$ (2,288)	$ (2,333)

The following table presents supplemental consolidated cash flow information related to lease payments for the years ended December 31, 2025 and 2024, respectively (in thousands).

	Year Ended December 31,	
	2025	2024
Cash paid related to lease liabilities		
Operating cash payments for operating leases	$ 36,725	$ 37,155
Investing cash payments for operating leases	$ 84,663	$ 87,776
Financing cash payments for finance leases	$ 1,466	$ 1,257
Right of use assets obtained in exchange for lease obligations entered into during the period		
Operating leases	$ 139,400	$ 207,279
Finance leases	$ 1,421	$ 1,467

The following table presents the maturities of lease liabilities at December 31, 2025 (in years).

Weighted-Average Remaining Lease Term	December 31, 2025
Operating leases	7.3
Finance leases	1.9

NOTE 4 — LEASES — Continued

The following table presents a schedule of future minimum lease payments required under all lease agreements as of December 31, 2025 (in thousands).

	December 31, 2025	
	Operating Leases	Finance Leases
2026	$ 65,091	$ 1,113
2027	25,690	808
2028	13,383	384
2029	7,618	—
2030	5,076	—
Thereafter	56,618	—
Total lease payments	173,476	2,305
Less imputed interest	(29,195)	(17)
Total lease obligations	144,281	2,288
Less current obligations	(65,091)	(1,113)
Long-term lease obligations	$ 79,190	$ 1,175

NOTE 5 — ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations primarily relate to future costs associated with plugging and abandonment of its oil, natural gas and salt water disposal wells, removal of pipelines, equipment and facilities from leased acreage and returning such land to its original condition. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and natural gas, future inflation rates and the Company's credit-adjusted risk-free interest rate. Revisions to the liability can occur due to changes in these estimates and assumptions or if federal or state regulators enact new plugging and abandonment requirements. At the time of the actual plugging and abandonment of its oil and natural gas wells, the Company includes any gain or loss associated with the operation in the amortization base to the extent the actual costs are different from the estimated liability.

The following table summarizes the changes in the Company's asset retirement obligations for the years ended December 31, 2025 and 2024 (in thousands).

	Year Ended December 31,	
	2025	2024
Beginning asset retirement obligations	$ 122,668	$ 92,090
Liabilities incurred during period	10,190	7,538
Liabilities settled during period	(1,674)	(1,188)
Revisions in estimated cash flows	17,141	16,351
Acquisitions during the period	—	7,487
Divestitures during the period	(5,799)	(5,637)
Accretion expense	7,846	6,027
Ending asset retirement obligations	150,372	122,668
Less: current asset retirement obligations[1]	(6,309)	(8,431)
Long-term asset retirement obligations	$ 144,063	$ 114,237

(1) Included in "Accrued liabilities" in the Company's consolidated balance sheets at December 31, 2025 and 2024.

NOTE 6 — BUSINESS COMBINATIONS AND DIVESTITURES

Business Combinations

San Mateo Joint Venture

On December 18, 2024, the Company completed a transaction with Five Point Infrastructure, LLC and its affiliates (previously, Five Point Energy LLC) ("Five Point") in which the Company contributed Pronto Midstream, LLC and its subsidiary ("Pronto"), a wholly-owned subsidiary of the Company, to San Mateo, and Five Point made a cash contribution to San Mateo of $171.5 million (the "Pronto Transaction"). In connection with the Pronto Transaction, the Company received a special distribution from San Mateo of approximately $219.8 million. In addition, the Company has the potential to earn up to $75.0 million in incentive payments from Five Point over a five-year period, of which $13.0 million and $1.3 million was paid by Five Point during the years ended December 31, 2025 and 2024, respectively. San Mateo continues to be owned 51% by the Company and 49% by Five Point, with Five Point's interest in San Mateo being accounted for as a non-controlling interest.

Subsequent to the Pronto Transaction, San Mateo owns and operates the expanded Marlan Processing Plant, which has a designed inlet capacity of 260 MMcf of natural gas per day, and operates Pronto's six compressor stations and approximately 150 miles of natural gas gathering pipelines in Lea and Eddy Counties, New Mexico.

In connection with the Pronto Transaction, the Company dedicated to San Mateo its current and certain future leasehold interests in the Ranger and Antelope Ridge asset areas pursuant to 15-year, fixed fee natural gas gathering, compression, treating and processing agreements whereby San Mateo will gather, compress, treat and process natural gas produced from the Company's operated wells in northern Lea County, New Mexico. In addition, San Mateo entered into certain agreements with Northwind Midstream Partners LLC ("Northwind"), previously an affiliate of Five Point, whereby Northwind will treat certain sour gas gathered and delivered by San Mateo in northern Lea County, New Mexico. Under these agreements, Northwind will redeliver the treated sweet gas from San Mateo and other third-party customers to San Mateo for processing.

Ameredev Acquisition

On September 18, 2024, a wholly-owned subsidiary of the Company completed the acquisition (the "Ameredev Acquisition") of Ameredev Stateline II, LLC ("Ameredev") from affiliates of EnCap Investments L.P., including (i) certain oil and natural gas producing properties and undeveloped acreage located in Lea County, New Mexico and Loving and Winkler Counties, Texas, and (ii) an approximate 19% stake (the "Piñon Investment") in the parent company of Piñon Midstream, LLC ("Piñon"). The Ameredev Acquisition had an effective date of June 1, 2024 and an aggregate as-adjusted closing purchase price of approximately $1.83 billion in cash. The purchase price for the Ameredev Acquisition was funded by a combination of cash on hand and borrowings under the Company's Credit Agreement, which was amended on September 18, 2024 to, among other things: (i) provide for a term loan of $250.0 million, the full amount of which was borrowed to fund the Ameredev Acquisition, and (ii) increase the elected borrowing commitments under the revolving credit facility from $1.50 billion to $2.25 billion. On September 25, 2024, the Company completed the sale of $750.0 million in aggregate principal amount of the Company's 6.25% senior unsecured notes due 2033 (the "2033 Notes") and used the net proceeds to partially repay borrowings outstanding under the Credit Agreement, including all of the $250.0 million in outstanding borrowings under the term loan.

The Ameredev Acquisition was accounted for under the acquisition method of accounting as a business combination in accordance with ASC Topic 805, *Business Combinations*. Under ASC Topic 805, the purchase price is allocated to the underlying tangible and intangible assets acquired and liabilities assumed based upon their estimated fair values as of the respective acquisition date, with any excess purchase price allocated to goodwill. As the Company acquired 100% of the membership interests of Ameredev, the acquisition was treated as an asset acquisition for tax purposes. The Company concluded that the Piñon Investment was an equity method investment.

NOTE 6 — BUSINESS COMBINATIONS AND DIVESTITURES — Continued

The final allocation of the total purchase price for the Ameredev Acquisition is set forth below (in thousands).

Consideration	Allocation
Cash consideration given	$ 1,831,214
Allocation of purchase price	
Current assets	$ 51,499
Oil and natural gas properties	
Evaluated	1,316,532
Unproved and unevaluated	316,586
Midstream assets	117,762
Equity method investment	115,819
Current liabilities	(80,651)
Asset retirement obligations	(6,333)
Net assets acquired	$ 1,831,214

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of evaluated oil and natural gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation.

Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) future production volumes, (ii) future commodity prices and (iii) recent market comparable transactions for unproved acreage. These inputs require significant judgments and estimates and are the most sensitive and subject to change.

Divestitures

During the first quarter of 2025, the Company sold its remaining South Texas assets in the Eagle Ford shale for $22.2 million. During 2024, the Company converted approximately $12.4 million of non-core assets to cash. These properties were primarily located in South Texas and Northwest Louisiana.

On October 28, 2024, Piñon was acquired by an affiliate of Enterprise Products Partners L.P. The Company received $113.6 million from the sale of Piñon during the fourth quarter of 2024 and used these proceeds to reduce borrowings under the Credit Agreement. The Company received an additional $3.3 million from the sale of Piñon in the first half of 2025.

NOTE 7 — DEBT

The components of debt, including the effects of issuance costs and discounts, net as of December 31, 2025 and 2024, are set forth below (in thousands).

	December 31,	
	2025	2024
Revolving credit agreements:		
Credit Agreement due 2029	$ 398,000	$ 595,500
San Mateo Credit Facility due 2029	883,000	615,000
Senior unsecured notes:		
6.875% senior notes due 2028 (the "2028 Notes")	500,000	500,000
6.500% senior notes due 2032 (the "2032 Notes")	900,000	900,000
6.250% senior notes due 2033 (the "2033 Notes")	750,000	750,000
Issuance costs and discounts, net	(28,898)	(35,092)
Total senior unsecured notes payable	2,121,102	2,114,908
Total long-term debt	$ 3,402,102	$ 3,325,408

Credit Agreements

MRC Energy Company

On November 18, 2021, the Company entered into its Fourth Amended and Restated Credit Agreement with the lenders party thereto. MRC Energy Company ("MRC"), a subsidiary of Matador that directly or indirectly holds the Company's ownership interests in its other operating subsidiaries, is the borrower under the Credit Agreement. Borrowings are secured by mortgages on at least 85% of MRC's and the Restricted Subsidiaries' (as defined in the Credit Agreement) proved oil and natural gas properties and by the equity interests of certain of MRC's wholly-owned subsidiaries, which are also guarantors. San Mateo is not a guarantor of the Credit Agreement. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC. The outstanding borrowings under the Credit Agreement mature on March 22, 2029 or, if earlier, the date that is up to 180 days prior to the earliest stated redemption date of any senior notes of the Company if unused availability under the revolving credit facility on such date is less than 20% of the aggregate revolving commitments, on a pro forma basis after giving effect to the repayment of such senior notes.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. The Company and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates.

In May and December 2025, the borrowing base of the Credit Agreement was reaffirmed at $3.25 billion, and the Company kept the elected borrowing commitments at $2.25 billion. The May and December 2025 reaffirmations of the borrowing base constituted the regularly scheduled May 1 and November 1 redeterminations, respectively.

In the event of an increase in the elected borrowing commitment, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the increase. If, upon a redetermination of the borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at such time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

Total deferred loan costs were $21.5 million at December 31, 2025, and these costs are being amortized over the term of the Credit Agreement. At December 31, 2025, the Company had $398.0 million in borrowings outstanding under the Credit Agreement and approximately $53.8 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Company's effective interest rate under the Credit Agreement was 5.63% at December 31, 2025.

NOTE 7 — DEBT — Continued

The applicable interest rate margin for borrowings under the Credit Agreement ranges from 1.75% to 2.75% for borrowings bearing interest with reference to Term SOFR (as defined in the Credit Agreement) and from 0.75% to 1.75% for borrowings bearing interest with reference to the Alternate Base Rate (as defined in the Credit Agreement), in each case depending on the level of borrowings under the Credit Agreement. The interest period for Term SOFR borrowings may be one, three or six months as designated by MRC. If MRC has outstanding borrowings under the Credit Agreement and interest rates increase, so will MRC's interest costs, which may have a material adverse effect on the Company's results of operations and financial condition.

A commitment fee of 0.375% to 0.50%, depending on the level of borrowings under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain (i) a current ratio, which is defined as (x) total consolidated current assets plus the unused availability under the Credit Agreement divided by (y) total consolidated current liabilities less current maturities of debt, of not less than 1.0 at the end of each fiscal quarter and (ii) a debt to EBITDA ratio, which is defined as debt outstanding (net of up to the greater of $150 million or 10% of the elected borrowing commitments of unrestricted cash and cash equivalents) divided by a rolling four quarter EBITDA calculation, of 3.50 or less at the end of each fiscal quarter.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit MRC's and its Restricted Subsidiaries' (as defined in the Credit Agreement) ability to take certain actions, including the following:

- incur indebtedness or grant liens on any of its assets;
- enter into commodity hedging agreements or interest rate agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of MRC's assets; and
- take certain actions with respect to the Company's senior unsecured notes.

If an event of default exists under the Credit Agreement, the lenders will be able to terminate their commitments, accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include the following:

- failure to pay any principal on the outstanding borrowings when due or any interest on the outstanding borrowings, any reimbursement obligation under any letter of credit or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or any of the Restricted Subsidiaries; and
- a change of control, as defined in the Credit Agreement.

The Company was in compliance with the terms of the Credit Agreement at December 31, 2025.

San Mateo Midstream, LLC

On December 19, 2018, San Mateo entered into a secured revolving credit facility (the "San Mateo Credit Facility") with the lenders party thereto. In June 2025, San Mateo and certain of its lenders modified the San Mateo Credit Facility to (i) increase the lender commitments from $800.0 million to $850.0 million and (ii) add one new bank to San Mateo's lending group. In December 2025, San Mateo and certain of its lenders amended the San Mateo Credit Facility to (i) increase the lender commitments from $850.0 million to $1.10 billion, (ii) reduce the borrowing rate and (iii) add one new bank to San Mateo's lending group. The San Mateo Credit Facility includes an accordion feature, which provides for potential increases in lender commitments of up to $1.35 billion. The San Mateo Credit Facility is non-recourse with respect to Matador and its other subsidiaries but is guaranteed by San Mateo's subsidiaries and secured by substantially all of San Mateo's assets, including real property.

NOTE 7 — DEBT — Continued

Total deferred loan costs were $9.3 million at December 31, 2025, and these costs are being amortized over the term of the San Mateo Credit Facility. San Mateo's effective interest rate under the San Mateo Credit Facility was 5.72% at December 31, 2025. At December 31, 2025, San Mateo had $883.0 million in borrowings outstanding under the San Mateo Credit Facility and $15.4 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility. The outstanding borrowings under the San Mateo Credit Facility mature on November 26, 2029.

Borrowings under the San Mateo Credit Facility may be in the form of a base rate loan or a SOFR loan. If San Mateo borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the San Mateo Credit Facility) on such day, plus 0.50%, and (iii) the Term SOFR (as defined in the San Mateo Credit Facility) for a one month tenor plus 1.0%, plus, in each case, an amount ranging from 1.00% to 2.00% depending on San Mateo's Consolidated Total Leverage Ratio (as defined in the San Mateo Credit Facility). If San Mateo borrows funds as a SOFR loan, such borrowings will bear interest at a rate equal to (x) Term SOFR for the chosen interest period plus (y) an amount ranging from 2.00% to 3.00% depending on San Mateo's Consolidated Total Leverage Ratio. The applicable margin for base rate loans and SOFR loans under the San Mateo Credit Facility will be decreased by 0.25% in the event of a Notes Offering (as defined in the San Mateo Credit Facility) or a Qualified IPO (as defined in the San Mateo Credit Facility). If San Mateo has outstanding borrowings under the San Mateo Credit Facility and interest rates increase, so will San Mateo's interest costs, which may have a material adverse effect on San Mateo's results of operations and financial condition.

A commitment fee of 0.30% to 0.50%, depending on San Mateo's Consolidated Total Leverage Ratio, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The San Mateo Credit Facility requires San Mateo to maintain a debt to EBITDA ratio, which is defined as total consolidated funded indebtedness outstanding (as defined in the San Mateo Credit Facility) divided by a rolling four quarter EBITDA calculation, of 5.00 or less, subject to certain exceptions. The San Mateo Credit Facility also requires San Mateo to maintain an interest coverage ratio, which is defined as a rolling four quarter EBITDA calculation divided by San Mateo's consolidated interest expense for such period, of 2.50 or more. The San Mateo Credit Facility also restricts the ability of San Mateo to distribute cash to its members if San Mateo's debt to EBITDA ratio is greater than 4.50 or San Mateo's liquidity is less than 10% of the lender commitments under the San Mateo Credit Facility.

Subject to certain exceptions, the San Mateo Credit Facility contains various covenants that limit San Mateo's and its restricted subsidiaries' ability to take certain actions, including the following:

- incur indebtedness or grant liens on any of San Mateo's assets;
- enter into hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of San Mateo's assets; and
- issue equity interests in San Mateo or its restricted subsidiaries.

If an event of default exists under the San Mateo Credit Facility, the lenders will be able to terminate their commitments, accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include the following:

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the San Mateo Credit Facility or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving San Mateo or its subsidiaries; and
- a change of control, as defined in the San Mateo Credit Facility.

San Mateo was in compliance with the terms of the San Mateo Credit Facility at December 31, 2025.

NOTE 7 — DEBT — Continued

Senior Unsecured Notes

2028 Notes

At December 31, 2025, the Company had $500.0 million in outstanding 2028 Notes, which have a 6.875% coupon rate and mature on April 15, 2028. Interest on the 2028 Notes is payable semi-annually in arrears on each April 15 and October 15. The 2028 Notes are jointly and severally guaranteed on a senior unsecured basis by certain subsidiaries of the Company (the "Guarantors"). San Mateo is not a Restricted Subsidiary (as defined in the indenture governing the 2028 Notes (the "2028 Notes Indenture")) or Guarantor of the 2028 Notes.

The Company may redeem all or a part of the 2028 Notes at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Redemption Price
2025	103.438%
2026	101.719%
2027 and thereafter	100.000%

Subject to certain exceptions, the 2028 Notes Indenture contains various covenants that limit the Company's and its Restricted Subsidiaries' ability to take certain actions, including the following:

- incur additional indebtedness;
- sell assets;
- pay dividends or make certain investments;
- create liens that secure indebtedness;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary (as defined in the 2028 Notes Indenture) that is a Significant Subsidiary (as defined in the 2028 Notes Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding 2028 Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2028 Notes may declare all the 2028 Notes to be due and payable immediately. Events of default include the following:

- default for 30 days in the payment when due of interest on the 2028 Notes;
- default in the payment when due of the principal of, or premium, if any, on the 2028 Notes;
- failure by the Company to comply with its obligations to offer to purchase or purchase 2028 Notes pursuant to the change of control or asset sale covenants of the 2028 Notes Indenture or to comply with the covenant relating to mergers;
- failure by the Company for 180 days after notice to comply with its reporting obligations under the 2028 Notes Indenture;
- failure by the Company for 60 days after notice to comply with any of the other agreements in the 2028 Notes Indenture;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $100.0 million or more;
- failure by the Company or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $100.0 million within 60 days;
- any subsidiary guarantee by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to the Company or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

NOTE 7 — DEBT — Continued

2032 Notes

At December 31, 2025, the Company had $900.0 million in outstanding 2032 Notes, which have a 6.50% coupon rate and mature on April 15, 2032. Interest on the 2032 Notes is payable in arrears on each April 15 and October 15. The 2032 Notes are jointly and severally guaranteed on a senior unsecured basis by the Guarantors. San Mateo is not a Restricted Subsidiary (as defined in the indenture governing the 2032 Notes (the "2032 Notes Indenture")) or Guarantor of the 2032 Notes.

At any time prior to April 15, 2027, the Company may redeem up to 40% in aggregate principal amount of 2032 Notes at a redemption price of 106.500% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, in an amount not greater than the net proceeds of certain equity offerings, so long as the redemption occurs within 180 days of completing such equity offering and at least 60% of the aggregate principal amount of the 2032 Notes remains outstanding after such redemption. In addition, at any time prior to April 15, 2027, the Company may redeem all or part of the 2032 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest, if any, to the applicable redemption date.

On or after April 15, 2027, the Company may redeem all or a part of the 2032 Notes at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Redemption Price
2027	103.250%
2028	101.625%
2029 and thereafter	100.000%

Subject to certain exceptions, the 2032 Notes Indenture contains various covenants that limit the Company's and its Restricted Subsidiaries' ability to take certain actions, including the following:

- incur additional indebtedness;
- sell assets;
- pay dividends or make certain investments;
- create liens that secure indebtedness;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary (as defined in the 2032 Notes Indenture) that is a Significant Subsidiary (as defined in the 2032 Notes Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding 2032 Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2032 Notes may declare all the 2032 Notes to be due and payable immediately. Events of default include the following:

- default for 30 days in the payment when due of interest on the 2032 Notes;
- default in the payment when due of the principal of, or premium, if any, on the 2032 Notes;
- failure by the Company to comply with its obligations to offer to purchase or purchase 2032 Notes pursuant to the change of control or asset sale covenants of the 2032 Notes Indenture or to comply with the covenant relating to mergers;
- failure by the Company for 180 days after notice to comply with its reporting obligations under the 2032 Notes Indenture;
- failure by the Company for 60 days after notice to comply with any of the other agreements in the 2032 Notes Indenture;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $100.0 million or more;
- failure by the Company or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $100.0 million within 60 days;

NOTE 7 — DEBT — Continued

- any subsidiary guarantee by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to the Company or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

2033 Notes

At December 31, 2025, the Company had $750.0 million in outstanding 2033 Notes, which have a 6.25% coupon rate and mature on April 15, 2033. Interest on the 2033 Notes is payable in arrears on each April 15 and October 15. The 2033 Notes are jointly and severally guaranteed on a senior unsecured basis by the Guarantors. San Mateo is not a Restricted Subsidiary (as defined in the indenture governing the 2033 Notes (the "2033 Notes Indenture")) or Guarantor of the 2033 Notes.

At any time prior to April 15, 2028, the Company may redeem up to 40% in aggregate principal amount of 2033 Notes at a redemption price of 106.250% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, in an amount not greater than the net proceeds of certain equity offerings, so long as the redemption occurs within 180 days of completing such equity offering and at least 60% of the aggregate principal amount of the 2033 Notes remains outstanding after such redemption. In addition, at any time prior to April 15, 2028, the Company may redeem all or part of the 2033 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest, if any, to the applicable redemption date.

On or after April 15, 2028, the Company may redeem all or a part of the 2033 Notes at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Redemption Price
2028	103.125%
2029	101.563%
2030 and thereafter	100.000%

Subject to certain exceptions, the 2033 Notes Indenture contains various covenants that limit the Company's and its Restricted Subsidiaries' ability to take certain actions, including the following:

- incur additional indebtedness;
- sell assets;
- pay dividends or make certain investments;
- create liens that secure indebtedness;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary (as defined in the 2033 Notes Indenture) that is a Significant Subsidiary (as defined in the 2033 Notes Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding 2033 Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2033 Notes may declare all the 2033 Notes to be due and payable immediately. Events of default include the following:

- default for 30 days in the payment when due of interest on the 2033 Notes;
- default in the payment when due of the principal of, or premium, if any, on the 2033 Notes;
- failure by the Company to comply with its obligations to offer to purchase or purchase 2033 Notes pursuant to the change of control or asset sale covenants of the 2033 Notes Indenture or to comply with the covenant relating to mergers;
- failure by the Company for 180 days after notice to comply with its reporting obligations under the 2033 Notes Indenture;
- failure by the Company for 60 days after notice to comply with any of the other agreements in the 2033 Notes Indenture;

NOTE 7 — DEBT — Continued

- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $100.0 million or more;
- failure by the Company or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $100.0 million within 60 days;
- any subsidiary guarantee by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to the Company or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

NOTE 8 — INCOME TAXES

On July 4, 2025, the One Big Beautiful Bill Act (the "OBBBA") was enacted. The legislation, among other things, makes permanent, extends or modifies certain provisions under the 2017 Tax Cuts and Jobs Act, including (i) a permanent extension of 100% bonus depreciation for certain capital expenditures, (ii) an immediate deduction of domestic research or experimental expenditures, (iii) an acceleration of deductions for unamortized domestic research and development expenditures and (iv) an elimination of the deduction for depreciation, amortization and depletion from the definition of "adjusted taxable income" for the purpose of calculating limitations on interest expense deductions. Pursuant to ASC Topic 740, *Income Taxes*, the effects of changes in tax law are recognized in the period of enactment, and as a result, the Company recognized the impacts of this legislation in its consolidated financial statements for the year ended December 31, 2025. While the enactment of OBBBA resulted in a decrease in the current income tax provision and corresponding increase in the deferred income tax provision for the year ended December 31, 2025, the effective income tax rates and the total income tax provision were not materially impacted.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position as of December 31, 2025 and 2024 is as follows (in thousands).

	December 31,	
	2025	2024
Deferred tax assets		
Net operating loss carryforwards	$ 118,860	$ 14,338
Lease liabilities	24,021	31,843
Compensation	17,615	16,562
Research and experimental tax credits, net of reserve	8,376	1,117
Interest expense carryforward	—	15,891
Other	2,553	1,677
Total deferred tax assets	171,425	81,428
Valuation allowance on deferred tax assets	$ (8,985)	(11,957)
Total deferred tax assets, net of valuation allowance	162,440	69,471
Deferred tax liabilities		
Property and equipment	(1,036,280)	(802,186)
Less than wholly-owned subsidiaries	(107,566)	(75,580)
Lease right of use assets	(24,021)	(31,843)
Unrealized gain on derivatives	(8,097)	(4,039)
Other	(2,407)	(3,489)
Total deferred tax liabilities	(1,178,371)	(917,137)
Net deferred tax liabilities	$ (1,015,931)	$ (847,666)

NOTE 8 — INCOME TAXES — Continued

At December 31, 2025, the Company had a federal net operating loss ("NOL") carryforward and research and experimental credit carryforward of $97.3 million and $10.4 million, respectively. The federal NOL carryforward is indefinite-lived, and the research and experimental credit carryforward expires in 2045. At December 31, 2025, the Company had state NOL carryforwards and research and experimental credit carryforwards of $21.5 million and $4.3 million, respectively. State NOL carryforwards were comprised of $11.1 million and $10.0 million related to Louisiana and New Mexico, respectively. The Louisiana NOL carryforwards are fully offset by a valuation allowance, and the New Mexico NOL carryforward expires in 2045. The state research and experimental credit carryforwards all relate to Texas and begin expiring in 2038.

The current income tax provision and the deferred income tax provision for the years ended December 31, 2025, 2024 and 2023 were comprised of the following (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Current income tax provision			
Federal	$ 6,192	$ 21,296	$ 1,554
State	896	5,763	12,368
Total current income tax provision	$ 7,088	$ 27,059	$ 13,922
Deferred income tax provision (benefit)			
Federal	$ 187,881	$ 221,356	$ 145,711
State	(22,294)	43,949	26,393
Total deferred income tax provision	$ 165,587	$ 265,305	$ 172,104
Total income tax provision (benefit)			
Federal	$ 194,073	242,652	147,265
State	(21,398)	49,712	38,761
Total income tax provision	$ 172,675	$ 292,364	$ 186,026

Reconciliations of expected income tax expense and reported income tax expense on income before income taxes for the years ended December 31, 2025, 2024 and 2023 are as follows (in thousands).

	Year Ended December 31,					
	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
US federal statutory income tax rate	$ 217,558	21.00 %	$ 265,379	21.00 %	$ 230,241	21.00 %
Federal						
Non-controlling interest in subsidiaries	(21,325)	(2.06)%	(18,064)	(1.43)%	(13,500)	(1.23)%
Research and experimental tax credits	(11,545)	(1.11)%	1,504	0.12 %	(102,330)	(9.33)%
Other nontaxable and nondeductible items	5,922	0.57 %	(3,931)	(0.31)%	3,558	0.32 %
State income tax (benefit) expense[1]	(21,398)	(2.06)%	47,927	3.79 %	37,358	3.41 %
Change in reserve on uncertain tax positions	3,463	0.33 %	(451)	(0.04)%	30,699	2.80 %
Total income tax provision	$ 172,675	16.67 %	$ 292,364	23.13 %	$ 186,026	16.97 %

(1) For the years ended December 31, 2025, 2024 and 2023, the state income tax (benefit) expense was primarily related to the State of New Mexico.

The Company did not have any reconciling items related to changes in tax laws or rates enacted in the current period.

The Company files a United States federal income tax return and several state tax returns, a number of which remain open for examination. The earliest tax year open for examination for the federal, the State of New Mexico and the State of Louisiana tax returns is 2022. The earliest tax year open for examination for the State of Texas tax return is 2021.

NOTE 8 — INCOME TAXES — Continued

As of December 31, 2025, 2024 and 2023, the Company had unrecognized tax benefits ("UTB") of $37.8 million, $34.3 million and $35.3 million, respectively, as a result of research and experimental expenditures, which would reduce the Company's effective tax rate in future periods if and when realized. As of December 31, 2025, 2024 and 2023, $31.5 million, $31.1 million and $27.0 million, respectively, of the Company's UTBs were recorded as other long-term liabilities on the consolidated balance sheets.

Reconciliations of UTBs for the years ended December 31, 2025, 2024 and 2023 are as follows (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Balance at beginning of period	$ 34,335	$ 35,336	$ —
Additions for tax positions of current period	3,111	2,745	35,336
Adjustment for tax positions of prior periods	352	(3,746)	—
Balance at end of period[1]	$ 37,798	$ 34,335	$ 35,336

(1) At December 31, 2025, 2024 and 2023, the UTBs related to U.S. federal taxes were $33.7 million, $30.2 million and $30.7 million, respectively. At each of December 31, 2025 and 2024, the UTBs related to state of Texas taxes were $4.1 million. At December 31, 2023, the UTBs related to state of Texas taxes were $4.6 million.

The Company's cash paid for income taxes, net of refunds received during the years ended December 31, 2025, 2024 and 2023 are as follows (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Federal	$ 43,000	$ 22,622	$ (8,864)
State			
New Mexico	7,500	7,200	13,284
Other	—	182	177
Total cash paid for income taxes, net of refunds received	$ 50,500	$ 30,004	$ 4,597

NOTE 9 — STOCK-BASED COMPENSATION

In 2019, the Board adopted and shareholders approved the 2019 Incentive Plan. In 2022, the Board adopted and shareholders approved the first amendment to the 2019 Incentive Plan authorizing an additional 3,725,000 shares of common stock for issuance to employees, directors, contractors or advisors of the Company. As of December 31, 2025, the 2019 Incentive Plan provided for a maximum of 2,902,512 shares of common stock in the aggregate that may be issued pursuant to grants of options, restricted stock, stock appreciation rights, restricted stock units or other performance award grants. The persons eligible to receive awards under the 2019 Incentive Plan include employees, directors, contractors or advisors of the Company. The primary purpose of the 2019 Incentive Plan is to attract and retain key employees, directors, contractors or advisors of the Company.

The 2019 Incentive Plan is administered by the independent members of the Board, who, upon recommendation of the Strategic Planning and Compensation Committee of the Board, determine the number of options, restricted shares or other awards to be granted, the effective dates, the terms of the grants and the vesting periods. The Company typically uses newly issued shares of common stock to satisfy option exercises or restricted share grants.

During the years ended December 31, 2025, 2024 and 2023, the Company granted both equity-based and liability-based awards under the 2019 Incentive Plan. The fair value of equity-based awards is fixed at the grant date, while the fair value of liability-based awards is remeasured at each reporting period.

NOTE 9 — STOCK-BASED COMPENSATION — Continued

Employee Stock Purchase Plan ("ESPP")

In 2022, the Board adopted and shareholders approved an ESPP, which authorizes a maximum of 4.0 million shares of common stock to be purchased. The purpose of the ESPP is to encourage and enable the Company's eligible employees to acquire an interest in the Company through the ownership of common stock. At December 31, 2025, the Company had 3,833,110 remaining shares available for issuance under the ESPP.

Restricted Stock, Restricted Stock Units and Common Stock

The Company has granted stock, restricted stock and restricted stock unit awards to employees, consultants, outside directors and advisors of the Company under the 2019 Incentive Plan. The stock and restricted stock are issued upon grant, with the restrictions, if any, being removed upon vesting. The equity-based restricted stock units are issued upon vesting, unless the recipient makes an election to defer issuance for a set term after vesting. Liability-based restricted stock units are settled in cash upon vesting. Restricted stock and restricted stock units granted in 2025, 2024 and 2023 were service-based awards, which will settle in cash or equity, and vest over a one-year to three-year period. Performance-based restricted stock units granted in 2025 and 2024 vest in an amount between zero and 200% of the target units granted based on the Company's relative total shareholder return over the three-year periods ending December 31, 2027 and 2026, respectively, as compared to a designated peer group, and will be settled in equity.

Equity-Based

A summary of the non-vested equity-based restricted stock and restricted stock units as of December 31, 2025 is presented below (in thousands, except fair value).

	Restricted Stock		Restricted Stock Units			
	Service Based		Service Based		Performance Based	
Non-vested restricted stock and restricted stock units	Shares	Weighted average fair value	Shares	Weighted average fair value	Shares	Weighted average fair value
Non-vested at December 31, 2024	701	$ 51.26	23	$ 59.21	501	$ 70.65
Granted	380	$ 51.58	38	$ 49.42	363	$ 62.41
Vested[1]	(196)	$ 51.30	(24)	$ 59.31	(179)	$ 65.49
Forfeited	(55)	$ 50.88	—	$ —	(55)	$ 66.32
Non-vested at December 31, 2025	830	$ 51.42	37	$ 49.02	630	$ 67.85

(1) On January 6, 2026 upon certification by the Board, 106,500 of the performance-based awards that were granted in 2023 vested. The vested units earned 58% for each vested award representing 61,770 aggregate shares of common stock, which were issued on January 6, 2026.

Liability-Based

A summary of the non-vested liability-based restricted stock units as of December 31, 2025 is presented below (in thousands).

Non-vested restricted stock units	Shares
Non-vested at December 31, 2024	494
Granted	474
Vested	(221)
Forfeited	(32)
Non-vested at December 31, 2025	715

During the years ended December 31, 2025, 2024 and 2023, the Company settled 220,669, 222,948 and 378,852 liability-based awards, respectively, for $11.2 million, $13.4 million and $20.5 million in cash, respectively.

At December 31, 2025, the aggregate intrinsic value for the restricted stock and restricted stock units outstanding was $94.7 million, of which $30.6 million is expected to be settled in cash as calculated based on the maximum number of shares of

NOTE 9 — STOCK-BASED COMPENSATION — Continued

restricted stock units vesting, based on the closing price of Matador's common stock on the appropriate date under the 2019 Incentive Plan.

At December 31, 2025, the total remaining unrecognized compensation expense related to unvested restricted stock and restricted stock units was approximately $67.5 million, of which $21.1 million is expected to be settled in cash. In accordance with the 2019 Incentive Plan, cash settlements are valued on the closing price of Matador's common stock on the trading day prior to vesting. The weighted average remaining requisite service period (vesting period) of all non-vested restricted stock and restricted stock units was 1.8 years.

The fair value of restricted stock and restricted stock units vested during 2025, 2024 and 2023 was $41.0 million, $29.4 million and $64.8 million, respectively.

Summary

During the years ended December 31, 2025, 2024 and 2023, the total expense attributable to restricted stock and restricted stock units was $39.8 million, $37.3 million and $33.0 million, respectively. During the years ended December 31, 2025, 2024 and 2023, the Company capitalized $13.3 million, $11.8 million and $7.4 million, respectively, related to stock-based compensation and expensed the remaining $26.5 million, $25.5 million and $25.6 million, respectively.

The total tax benefit recognized for all stock-based compensation was $8.5 million, $8.0 million and $7.0 million for the years ended December 31, 2025, 2024 and 2023, respectively.

NOTE 10 — EMPLOYEE BENEFIT PLANS

401(k) Plan

All full-time Company employees are eligible to join the Company's defined contribution retirement plan the first day of the calendar month immediately following their date of employment. Each employee may contribute up to the maximum allowable under the Internal Revenue Code. Each year, the Company makes a contribution to the plan that equals 3% of the employee's annual compensation, up to the maximum allowable under the Internal Revenue Code, referred to as the Employer's Safe Harbor Non-Elective Contribution, which totaled $2.9 million, $2.6 million and $2.2 million in 2025, 2024 and 2023, respectively. In addition, each year, the Company may make a discretionary matching contribution, as well as additional contributions. The Company's discretionary matching contributions totaled $3.7 million, $3.3 million and $2.8 million in 2025, 2024 and 2023, respectively. The Company made no additional contributions in any reporting period presented.

NOTE 11 — EQUITY

Equity Offering

On March 28, 2024, the Company completed an underwritten public offering of 5,250,000 shares of its common stock. After deducting underwriting discounts and offering expenses, the Company received net proceeds of approximately $342.1 million. The net proceeds from this offering were used for general corporate purposes, including the funding of acquisitions and the repayment of borrowings outstanding under the Credit Agreement.

Common Stock Dividend

The Board declared a quarterly cash dividend of $0.3125 per share of common stock in each of the first, second and third quarters of 2025. The first quarter dividend, which totaled $39.2 million, was paid on March 14, 2025 to shareholders of record as of February 28, 2025. The second quarter dividend, which totaled $39.0 million, was paid on June 6, 2025 to shareholders of record as of May 9, 2025. The third quarter dividend, which totaled $38.7 million, was paid on September 5, 2025 to shareholders of record as of August 15, 2025. On October 15, 2025, the Board amended the Company's dividend policy to increase the quarterly dividend to $0.375 per share of common stock for future dividend payments and also declared a quarterly cash dividend of $0.375 per share of common stock. The fourth quarter dividend, which totaled $46.2 million, was paid on December 5, 2025 to shareholders of record as of November 10, 2025.

The Board declared a quarterly cash dividend of $0.20 per share of common stock in each of the first, second and third quarters of 2024 and the Board declared a quarterly cash dividend of $0.25 per share of common stock in the fourth quarter of 2024.

Total cash dividends declared and paid totaled $163.1 million and $104.9 million, respectively, during the years ended December 31, 2025 and 2024.

NOTE 11 — EQUITY — Continued

Share Repurchase Program

On April 16, 2025, the Board approved a share repurchase program (the "Share Repurchase Program") authorizing the repurchase of up to $400.0 million of common stock. These repurchases may be conducted through a variety of methods, including open market purchases, 10b5-1 trading plans, privately negotiated transactions or other means.

During the year ended December 31, 2025, the Company repurchased 1,351,328 shares of common stock under the Share Repurchase Program at a weighted average price of $41.31 per common share for a total cost of $55.8 million.

Treasury Stock

On October 15, 2025, October 17, 2024 and October 19, 2023, the Board canceled all of the shares of treasury stock outstanding as of September 30, 2025, 2024 and 2023, respectively. These shares were restored to the status of authorized but unissued shares of common stock of the Company.

The shares of treasury stock outstanding at December 31, 2025, 2024 and 2023 represent shares traded by employees to cover taxes on vested restricted stock awards and forfeitures of unvested restricted stock awards.

Preferred Stock

The Company's Amended and Restated Certificate of Formation authorizes 2,000,000 shares of preferred stock. Before any such shares are issued, the Board shall fix and determine the designations, preferences, limitations and relative rights, including voting rights of the shares of each such series. There are no shares of preferred stock outstanding.

San Mateo Distributions and Contributions

During the years ended December 31, 2025, 2024 and 2023, San Mateo distributed $136.7 million, $321.2 million and $81.4 million, respectively, to the Company and $131.3 million, $97.5 million and $78.3 million, respectively, to Five Point, the Company's joint venture partner in San Mateo.

During the year ended December 31, 2025, neither the Company nor Five Point contributed cash to San Mateo. During the years ended December 31, 2024 and 2023, the Company contributed $19.9 million and $25.5 million, respectively, and Five Point contributed $190.6 million and $24.5 million, respectively, of cash to San Mateo.

San Mateo's 2024 distributions to the Company included a special distribution of approximately $219.8 million, of which $171.5 million represented a special contribution by Five Point recorded within the Company's statement of changes in shareholders' equity in connection with the Pronto Transaction. San Mateo's remaining special distribution to the Company of $48.3 million represented a reimbursement of certain capital expenditures for the expansion of the Marlan Processing Plant that were previously funded by Matador. See Note 6 for additional details.

Performance Incentives

As part of the joint venture with Five Point, the Company has the potential to earn performance incentives. During the years ended December 31, 2025, 2024 and 2023, Five Point paid the Company $13.0 million, $23.8 million and $38.2 million, respectively, in performance incentives, which were recorded when received in "Additional paid-in-capital" in the Company's consolidated balance sheets, net of $2.7 million, $5.0 million and $8.0 million of deferred tax impacts, for the years ended December 31, 2025, 2024 and 2023, respectively. Through April 1, 2029, the Company has the potential to earn an additional $60.7 million of performance incentives.

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and NGL prices. The Company records derivative financial instruments on its consolidated balance sheets as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of income as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company has evaluated and considered the credit standings of its counterparties in determining the fair value of its derivative financial instruments.

At December 31, 2025, the Company had various costless collar contracts open and in place to mitigate its exposure to oil price volatility, each with an established price floor and ceiling. At December 31, 2025, the Company had natural gas basis

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

differential swap contracts open and in place to mitigate its exposure to natural gas price volatility, with a specific term (calculation period), notional quantity (volume hedged) and fixed price. The Company had no open contracts associated with NGL prices at December 31, 2025.

The following is a summary of the Company's open costless collar contracts at December 31, 2025.

Commodity	Calculation Period	Notional Quantity (Bbl or MMBtu)	Weighted Average Price Floor ($/Bbl or $/MMBtu)	Weighted Average Price Ceiling ($/Bbl or $/MMBtu)	Fair Value of Asset (Liability) (thousands)
Oil	01/01/2026 - 12/31/2026	6,752,500	$ 50.00	$ 65.00	$ 717
Natural Gas	01/01/2026 - 12/31/2026	54,750,000	$ 3.50	$ 6.70	17,396
Total open costless collar contracts					$ 18,113

The following is a summary of the Company's open basis differential swap contracts at December 31, 2025.

Commodity	Calculation Period	Notional Quantity (MMBtu)	Fixed Price ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas Basis Differential	01/01/2026 - 12/31/2026	54,750,000	$ (2.52)	$ 15,939
Total open basis differential swap contracts				$ 15,939

The Company's derivative financial instruments are subject to master netting arrangements, and the Company's counterparties allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheets.

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the consolidated balance sheets as of December 31, 2025 and December 31, 2024 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the consolidated balance sheets	Net amounts presented in the consolidated balance sheets
December 31, 2025			
Current assets	$ 57,450	$ (23,398)	$ 34,052
Current liabilities	(23,398)	23,398	—
Total	$ 34,052	$ —	$ 34,052
December 31, 2024			
Current assets	$ 19,899	$ (3,931)	$ 15,968
Current liabilities	(3,931)	3,931	—
Total	$ 15,968	$ —	$ 15,968

The following table summarizes the location and aggregate gain (loss) of all derivative financial instruments recorded in the consolidated statements of income for the periods presented (in thousands).

		Year Ended December 31,		
Type of Instrument	Location in Statements of Income	2025	2024	2023
Derivative Instrument				
Natural Gas	Revenues: Realized gain (loss) on derivatives	$ 21,679	$ 12,724	$ (9,575)
Realized gain (loss) on derivatives		21,679	12,724	(9,575)
Oil	Revenues: Unrealized (loss) gain on derivatives	(2,958)	3,676	—
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	21,042	9,623	(1,261)
Unrealized gain (loss) on derivatives		18,084	13,299	(1,261)
Total		$ 39,763	$ 26,023	$ (10,836)

NOTE 13 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices for identical, unrestricted assets or liabilities in active markets.

Level 2 Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued with industry standard models that consider various inputs, including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data that reflect a company's own market assumptions.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of December 31, 2025 and 2024 (in thousands).

	Fair Value Measurements at December 31, 2025 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Oil costless collars	$ —	$ 717	$ —	$ 717
Natural gas costless collars	—	17,396	—	17,396
Natural gas basis differential swaps	—	15,939	—	15,939
Total	$ —	$ 34,052	$ —	$ 34,052

	Fair Value Measurements at December 31, 2024 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Oil costless collars	$ —	$ 3,676	$ —	$ 3,676
Natural gas basis differential swaps	—	12,292	—	12,292
Total	$ —	$ 15,968	$ —	$ 15,968

Additional disclosures related to derivative financial instruments are provided in Note 12.

Other Fair Value Measurements

At December 31, 2025 and 2024, the carrying values reported on the consolidated balance sheets for accounts receivable, prepaid expenses and other current assets, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners and other current liabilities approximated their fair values due to their short-term maturities.

At December 31, 2025 and 2024, the carrying value of borrowings under the Credit Agreement and the San Mateo Credit Facility approximated their fair value as both are subject to short-term floating interest rates that reflect market rates available to the Company at the time and are classified at Level 2 in the fair value hierarchy.

NOTE 13 — FAIR VALUE MEASUREMENTS — Continued

The following table summarizes the carrying value and fair value of outstanding senior unsecured notes at December 31, 2025 and 2024 (in thousands).

		December 31, 2025		December 31, 2024	
	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
2028 Notes	Level 1	$ 500,000	$ 511,585	$ 500,000	$ 505,380
2032 Notes	Level 1	$ 900,000	$ 914,265	$ 900,000	$ 890,667
2033 Notes	Level 1	$ 750,000	$ 751,920	$ 750,000	$ 730,568

Certain assets and liabilities are measured at fair value on a nonrecurring basis, including assets and liabilities acquired in a business combination, lease and well equipment inventory when the market value is determined to be lower than the cost of the inventory and other property and equipment that are reduced to fair value when they are impaired or held for sale. The Company recorded no material impairments to its lease and well equipment inventory or other property and equipment in 2025 and 2024.

NOTE 14 — COMMITMENTS AND CONTINGENCIES

Processing, Transportation and Produced Water Disposal Commitments

Firm Commitments

From time to time, the Company enters into agreements with third parties whereby the Company commits to deliver anticipated natural gas and oil production and produced water from certain portions of its acreage for gathering, transportation, processing, fractionation, sales and disposal. The Company paid approximately $85.8 million and $68.3 million for deliveries under these agreements during the years ended December 31, 2025 and 2024, respectively. Certain of these agreements contain minimum volume commitments, including agreements with Northwind that were entered into in connection with the Pronto Transaction in 2024 (see Note 6 for additional details), as well as contracts related to firm transportation on Energy Transfer's Hugh Brinson Pipeline. If the Company does not meet the minimum volume commitments under these agreements, it will be required to pay deficiency fees. If the Company ceased operations in the areas subject to these agreements at December 31, 2025, the total deficiencies required to be paid by the Company under these agreements would be approximately $2.32 billion.

San Mateo Commitments

The Company dedicated to San Mateo its current and certain future leasehold interests in the Rustler Breaks asset area and the Wolf portion of the West Texas asset area and acreage in the southern portion of its Arrowhead asset area (the "Greater Stebbins Area") and the Stateline asset area pursuant to 15-year, fixed-fee oil transportation, oil, natural gas and produced water gathering and produced water disposal agreements. In addition, the Company dedicated to San Mateo its current and certain future leasehold interests in the Rustler Breaks asset area and acreage in the Greater Stebbins Area and Stateline asset area pursuant to 15-year, fixed-fee natural gas processing agreements. In connection with the Pronto Transaction, the Company also dedicated to San Mateo certain of its current and future leasehold interests in the Ranger and Antelope Ridge asset areas pursuant to 15-year, fixed-fee natural gas gathering, compression, treating and processing agreements (collectively with the transportation, gathering, produced water disposal and natural gas processing agreements, the "Operational Agreements"). San Mateo provides the Company with firm service under each of the Operational Agreements in exchange for certain minimum volume commitments. See Note 6 for additional details. The remaining minimum contractual obligation under the Operational Agreements at December 31, 2025 was approximately $743.9 million.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided. The Company would incur a termination obligation if the Company elected to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $22.6 million at December 31, 2025.

NOTE 14 — COMMITMENTS AND CONTINGENCIES — Continued

At December 31, 2025, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company's undiscounted minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $79.0 million at December 31, 2025. The Company expects these costs to be incurred within the next year.

Legal Proceedings

The Company is a party to several legal proceedings encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these legal proceedings will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

NOTE 15 — SUPPLEMENTAL DISCLOSURES

Accounts Payable and Accrued Liabilities

The following table summarizes the Company's current accounts payable and accrued liabilities at December 31, 2025 and 2024 (in thousands).

	December 31,	
	2025	2024
Accounts payable	$ 179,337	$ 147,139
Accrued evaluated and unproved and unevaluated property costs	151,680	197,817
Accrued lease operating expenses	85,009	92,364
Accrued compensation and benefits	33,162	30,544
Accrued interest on debt	32,157	34,769
Accrued partners' share of joint interest charges	24,427	41,614
Accrued payable related to purchased natural gas	10,530	9,063
Accrued midstream properties costs	7,648	31,595
Accrued asset retirement obligations	6,309	8,431
Other	10,361	25,831
Total accounts payable and accrued liabilities	$ 540,620	$ 619,167

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the years ended December 31, 2025, 2024 and 2023 (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Cash paid for interest expense, net of amounts capitalized	$ 196,368	$ 160,273	$ 111,742
Increase in asset retirement obligations related to mineral properties	$ 18,310	$ 23,773	$ 33,209
Increase in asset retirement obligations related to midstream properties	$ 1,548	$ 777	$ 1,197
(Decrease) increase in liabilities for drilling, completion and equipping capital expenditures	$ (37,127)	$ 79,363	$ 31,364
Increase in liabilities for acquisition of oil and natural gas properties	$ 52	$ 212	$ 709
(Decrease) increase in liabilities for midstream capital expenditures	$ (23,850)	$ (23,789)	$ 43,572
Stock-based compensation expense recognized as liability	$ 11,451	$ 13,565	$ 11,380
Transfer of inventory (to) from oil and natural gas properties	$ (29,124)	$ (14,904)	$ 933

NOTE 15 — SUPPLEMENTAL DISCLOSURES

The following table provides a reconciliation of cash and restricted cash recorded in the consolidated balance sheets to cash and restricted cash as presented on the consolidated statements of cash flows (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Cash	$ 15,314	$ 23,033	$ 52,662
Restricted cash	64,163	71,709	53,636
Total cash and restricted cash	$ 79,477	$ 94,742	$ 106,298

NOTE 16 — SEGMENT INFORMATION

The Company has two reportable business segments: (i) exploration and production and (ii) midstream. The exploration and production segment is engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States and is currently focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also has operations in the Haynesville shale and Cotton Valley plays in Northwest Louisiana. The midstream segment conducts midstream operations in support of, and provides flow assurance for, the Company's exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and produced water gathering services and produced water disposal services to third parties. The majority of the Company's midstream operations in the Delaware Basin are conducted through San Mateo.

The Company's chief operating decision maker ("CODM") is the Chairman and Chief Executive Officer. The CODM uses operating income to assess income generated from each segment to allocate resources by either reinvesting profits as midstream or drilling and completion capital expenditures, or for determining the appropriate amounts for acquisition spend, the repayment of debt, the payment of dividends and repurchases of common stock.

The following tables present selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis, corporate expenses that are not allocated to a segment and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis (in thousands). On a consolidated basis, midstream services revenues consist primarily of those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues associated with Company-owned production are eliminated in consolidation. In evaluating the operating results of the exploration and production and midstream segments, the Company does not allocate certain expenses to the individual segments, including general and administrative expenses. Such expenses are reflected in the column labeled "Corporate."

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2025					
Oil and natural gas revenues	$ 3,227,055	$ 11,695	$ —	$ —	$ 3,238,750
Midstream services revenues	—	549,865	—	(385,132)	164,733
Sales of purchased natural gas	99,346	153,685	—	—	253,031
Realized gain on derivatives	21,679	—	—	—	21,679
Unrealized gain on derivatives	18,084	—	—	—	18,084
Operating expense[1]	588,285	208,142	—	(172,475)	623,952
Other expenses[2]	1,712,988	228,834	116,618	(212,657)	1,845,783
Operating income[3]	$ 1,064,891	$ 278,269	$ (116,618)	$ —	$ 1,226,542
Total assets[4]	$ 9,737,486	$ 1,833,673	$ 139,410	$ —	$ 11,710,569
Capital expenditures[5]	$ 1,864,889	$ 286,294	$ 4,246	$ —	$ 2,155,429

(1) Operating expense includes lease operating expense for the exploration and production segment and midstream operating expense for the midstream segment.

NOTE 16 — SEGMENT INFORMATION — Continued

(2) Includes depletion, depreciation and amortization expenses of $1.14 billion and $57.4 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.6 million. Other expenses for each reportable segment also includes (i) transportation and processing, (ii) general and administrative expenses, (iii) accretion of asset retirement obligations, (iv) purchased natural gas and (v) taxes other than income.

(3) Includes $101.5 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(4) Excludes intercompany receivables and investments in subsidiaries.

(5) Includes $339.2 million attributable to land and seismic acquisition expenditures related to the exploration and production segment and $118.4 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2024					
Oil and natural gas revenues	$ 3,129,598	$ 14,236	$ —	$ —	3,143,834
Midstream services revenues	—	453,464	—	(312,437)	141,027
Sales of purchased natural gas	22,186	171,911	—	—	194,097
Realized gain on derivatives	12,724	—	—	—	12,724
Unrealized gain on derivatives	13,299	—	—	—	13,299
Operating expense[1]	488,507	167,400	—	(163,362)	492,545
Other expenses[2]	1,386,821	226,218	113,774	(149,075)	1,577,738
Operating income[3]	$ 1,302,479	$ 245,993	$ (113,774)	$ —	$ 1,434,698
Total assets[4]	$ 9,117,095	$ 1,613,936	$ 119,078	$ —	$ 10,850,109
Capital expenditures[5]	$ 3,396,543	$ 504,315	$ 5,691	$ —	$ 3,906,549

(1) Operating expense includes lease operating expense for the exploration and production segment and midstream operating expense for the midstream segment.

(2) Includes depletion, depreciation and amortization expenses of $929.0 million and $43.9 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.4 million. Other expenses for each reportable segment also includes (i) transportation and processing, (ii) general and administrative expenses, (iii) accretion of asset retirement obligations, (iv) purchased natural gas and (v) taxes other than income.

(3) Includes $86.0 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(4) Excludes intercompany receivables and investments in subsidiaries.

(5) Includes $2.08 billion attributable to land and seismic acquisition expenditures related to the exploration and production segment, $236.2 million in midstream acquisition expenditures and $29.5 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 16 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2023					
Oil and natural gas revenues	$ 2,538,813	$ 6,786	$ —	$ —	$ 2,545,599
Midstream services revenues	—	346,933	—	(224,780)	122,153
Sales of purchased natural gas	23,521	126,348	—	—	149,869
Realized loss on derivatives	(9,575)	—	—	—	(9,575)
Unrealized loss on derivatives	(1,261)	—	—	—	(1,261)
Operating expense[1]	347,655	124,021	—	(115,134)	356,542
Other expenses[2]	1,070,302	180,903	99,362	(109,646)	1,240,921
Operating income[3]	$ 1,133,541	$ 175,143	$ (99,362)	$ —	$ 1,209,322
Total assets[4]	$ 6,385,762	$ 1,257,988	$ 83,246	$ —	$ 7,726,996
Capital expenditures[5]	$ 2,970,230	$ 254,393	$ 3,636	$ —	$ 3,228,259

(1) Operating expense includes lease operating expense for the exploration and production segment and midstream operating expense for the midstream segment.

(2) Includes depletion, depreciation and amortization expenses of $675.0 million and $40.4 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.3 million. Other expenses for each reportable segment also includes (i) transportation and processing, (ii) general and administrative expenses, (iii) accretion of asset retirement obligations (iv) purchased natural gas and (v) taxes other than income.

(3) Includes $64.3 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(4) Excludes intercompany receivables and investments in subsidiaries.

(5) Includes $1.81 billion attributable to land and seismic acquisition expenditures related to the exploration and production segment, $63.6 million in midstream acquisition expenditures and $42.2 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES

Costs Incurred

The following table summarizes costs incurred and capitalized by the Company in the acquisition, exploration and development of oil and natural gas properties for the years ended December 31, 2025, 2024 and 2023 (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Property acquisition costs			
Proved[1]	$ 84,102	$ 1,488,033	$ 1,478,258
Unproved and unevaluated	252,020	575,046	328,579
Exploration costs	152,016	71,381	230,712
Development costs	1,403,772	1,287,221	966,338
Total costs incurred[2]	$ 1,891,910	$ 3,421,681	$ 3,003,887

(1) Includes $60.4 million, $11.6 million and $1.8 million of D/C/E capital expenditures related to carried-interest agreements for the years ended December 31, 2025, 2024 and 2023, respectively.

(2) Excludes midstream-related development and corporate costs of approximately $290.5 million, $510.0 million and $258.0 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, including both unproved and unevaluated leasehold and purchases of reserves in place. For the year ended December 31, 2024, a majority of the Company's property acquisition costs resulted from the Ameredev Acquisition. For the year ended December 31, 2023, a majority of the Company's property acquisition costs resulted from its acquisition of Advance Energy Partners Holdings, LLC from affiliates of EnCap Investments L.P. on April 12, 2023 and its acquisition of additional interests from affiliates of EnCap Investments L.P., including overriding royalty interests and royalty interests in certain oil and natural gas properties located primarily in Lea County, New Mexico, on December 1, 2023 (collectively, the "Advance Acquisition").

Exploration costs are costs incurred in identifying areas of these oil and natural gas properties that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and costs of carrying and retaining unproved and unevaluated properties. Exploration costs may be incurred before or after acquiring the related oil and natural gas properties. For the year ended December 31, 2025 and 2024, the Company capitalized $2.6 million and $11.3 million of geological and geophysical costs, respectively, which are included as exploration costs in the table above. The Company did not capitalize any geological and geophysical costs in 2023.

Development costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil and natural gas. Development costs include the costs of preparing well locations for drilling, completing and equipping development wells and acquiring, constructing and installing production facilities.

Costs incurred also include newly established asset retirement obligations, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table above were increases of $20.0 million, $25.1 million and $33.8 million for the years ended December 31, 2025, 2024 and 2023, respectively. Capitalized general and administrative expenses that are directly related to acquisition, exploration and development activities are also included in the table above. The Company capitalized $71.7 million, $66.6 million and $54.2 million of these internal costs for the years ended December 31, 2025, 2024 and 2023, respectively, excluding midstream-related capitalized general and administrative expenses. Capitalized interest expense for qualifying projects is also included in the table above. The Company capitalized $21.2 million, $17.5 million and $20.2 million of its interest expense for the years ended December 31, 2025, 2024 and 2023, respectively, excluding midstream-related capitalized interest expense.

Oil and Natural Gas Reserves

Proved reserves are the 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. Estimating oil and natural gas reserves is complex and inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations of that data can vary. The process also requires certain economic assumptions, including assumptions related to oil and natural gas prices, drilling, completion and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from the Company's estimates.

The Company reports its production and proved reserves in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where the Company produces liquids-rich natural gas, such as in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas, the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold. The Company's oil and natural gas reserves estimates for the years ended December 31, 2025, 2024 and 2023 were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period from January through December 2025, these average oil and natural gas prices were $61.82 per Bbl and $3.39 per MMBtu, respectively. For the period from January through December 2024, these average oil and natural gas prices were $71.96 per Bbl and $2.13 per MMBtu, respectively. For the period from January through December 2023, these average oil and natural gas prices were $74.70 per Bbl and $2.64 per MMBtu, respectively.

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SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized as follows. All of the Company's oil and natural gas reserves are attributable to properties located in the United States. The estimated reserves shown below are proved reserves only and do not include any value for unproved reserves classified as probable or possible reserves that might exist for these properties, nor do they include any consideration that could be attributed to interests in unevaluated acreage beyond those tracts for which reserves have been estimated. In the tables presented throughout this section, natural gas is converted to oil equivalent using the ratio of one Bbl of oil to six Mcf of natural gas.

	Net Proved Reserves		
	Oil	Natural Gas	Oil Equivalent
	(MBbl)	(MMcf)	(MBOE)
Total at December 31, 2022	196,289	962,594	356,722
Revisions of prior estimates	(31,184)	(88,779)	(45,981)
Net acquisitions of minerals-in-place	78,550	183,311	109,102
Extensions and discoveries	56,164	193,054	88,339
Production	(27,542)	(123,420)	(48,112)
Total at December 31, 2023	272,277	1,126,760	460,070
Revisions of prior estimates	(11,264)	32,640	(5,824)
Net acquisitions of minerals-in-place	73,347	279,170	119,875
Extensions and discoveries	64,012	215,389	99,910
Production	(36,530)	(155,790)	(62,495)
Total at December 31, 2024	361,842	1,498,169	611,536
Revisions of prior estimates	(19,755)	75,258	(7,212)
Net acquisitions of minerals-in-place	1,768	9,345	3,326
Extensions and discoveries	75,819	354,920	134,972
Production	(43,694)	(191,288)	(75,575)
Total at December 31, 2025	375,980	1,746,404	667,047
Proved Developed Reserves			
December 31, 2022	116,030	632,858	221,507
December 31, 2023	161,642	782,733	292,097
December 31, 2024	206,269	963,170	366,797
December 31, 2025	223,028	1,109,755	407,987
Proved Undeveloped Reserves			
December 31, 2022	80,259	329,736	135,215
December 31, 2023	110,635	344,026	167,973
December 31, 2024	155,573	534,999	244,740
December 31, 2025	152,952	636,649	259,060

The following is a discussion of the changes in the Company's proved oil and natural gas reserves estimates for the years ended December 31, 2025, 2024 and 2023.

The Company's proved oil and natural gas reserves increased 9% from 611.5 million BOE at December 31, 2024 to 667.0 million BOE at December 31, 2025. The Company's proved oil and natural gas reserves increased by 131.1 million BOE and the Company produced 75.6 million BOE during the year ended December 31, 2025, resulting in a net increase of 55.5 million BOE. This increase in proved oil and natural gas reserves was primarily attributable to the Company's delineation and development operations in the Delaware Basin during 2025. The Company also added 135.0 million BOE in proved reserves through extensions and discoveries during 2025, of which 23.0 million BOE resulted from new well locations turned to sales during 2025 to establish proved developed reserves and 112.0 million BOE resulted from new proved undeveloped locations identified as a result of drilling activities on the Company's existing acreage in the Delaware Basin during 2025. The Company also increased its total proved oil and natural gas reserves by 3.3 million BOE as a result of net acquisitions, divestitures and trades during 2025. Additionally, the Company realized approximately 7.2 million BOE in net downward revisions of prior

estimates for proved oil and natural gas reserves in 2025, which primarily included the removal of 22.8 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of the Company's properties in the Delaware Basin, 5.6 million BOE resulting from pricing updates, including the 14% decrease in oil prices, which was partially offset by the 59% increase in natural gas prices used to estimate total proved reserves at December 31, 2025, as compared to December 31, 2024, and 2.9 million BOE in expense updates. As the Company continues to develop its Delaware Basin assets, the Company may reclassify some or all of this 22.8 million BOE to proved reserves at a future date. These downward revisions at December 31, 2025 were partially offset by positive forecast updates of 24.1 million BOE.

The Company's proved developed oil and natural gas reserves increased 11% from 366.8 million BOE at December 31, 2024 to 408.0 million BOE at December 31, 2025. The Company's proved developed oil and natural gas reserves increased by 116.8 million BOE and the Company produced 75.6 million BOE during the year ended December 31, 2025, resulting in a net increase of 41.2 million BOE. The Company added 23.0 million BOE in proved developed reserves through extensions and discoveries during 2025, which resulted from new well locations drilled during 2025 to establish proved reserves. In addition, during 2025 the Company converted 77.6 million BOE of its proved undeveloped reserves to proved developed reserves primarily through its development activities in the Delaware Basin. The Company also increased its proved developed reserves by 3.4 million BOE at December 31, 2025 as a result of net property acquisitions, divestitures and trades completed during 2025. Additionally, the Company realized approximately 12.8 million BOE in net upward revisions of prior estimates of proved developed reserves in 2025, including positive forecast updates of 16.7 million BOE and ownership updates of 3.2 million BOE. These upward revisions were partially offset by downward revisions of 4.2 million BOE and 2.9 million BOE attributable to certain pricing and expense updates used to estimate proved developed reserves at December 31, 2025 and 2024, respectively.

The Company's proved undeveloped oil and natural gas reserves increased 6% from 244.7 million BOE at December 31, 2024 to 259.1 million at December 31, 2025. The Company added 112.0 million BOE in proved undeveloped reserves through extensions and discoveries during 2025, which resulted primarily from new proved undeveloped locations identified as a result of drilling activities on the Company's existing acreage in the Delaware Basin during 2025. The Company also decreased its proved undeveloped reserves by 0.1 million BOE at December 31, 2025 as a result of net property acquisitions, divestitures and trades completed during 2025. Additionally, the Company realized approximately 20.0 million BOE in net downward revisions of prior estimates of proved undeveloped reserves in 2025, which included the removal of 22.8 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of the properties in the Delaware Basin and the removal of 3.2 million BOE and 1.4 million BOE for certain ownership and pricing updates at December 31, 2025 and 2024, respectively. These downward revisions were partially offset by positive forecast updates of 7.4 million BOE.

At December 31, 2025, the Company's proved reserves were comprised of 56% oil and 44% natural gas. As a percentage of total proved reserves, proved developed reserves were approximately 61% and proved undeveloped reserves were 39% at December 31, 2025. Comparatively, proved developed reserves as a percentage of total proved reserves were 60% and 63% at December 31, 2024 and 2023, respectively. The percent increase in proved developed reserves over proved undeveloped reserves from December 31, 2024 to December 31, 2025 was primarily a result of acquisitions and new wells drilled that resulted in proved developed reserves at a greater pace than extensions and discoveries of new proved undeveloped locations on the Company's existing acreage in the Delaware Basin. The percent decrease in proved developed reserves over proved undeveloped reserves from December 31, 2023 to December 31, 2024 was primarily the result of greater extensions and discoveries of new proved undeveloped locations on the Company's existing acreage in the Delaware Basin and proved undeveloped reserves acquired as part of the Ameredev Acquisition.

The Company's proved oil and natural gas reserves increased 33% from 460.1 million BOE at December 31, 2023 to 611.5 million BOE at December 31, 2024. The Company's proved oil and natural gas reserves increased by 214.0 million BOE and the Company produced 62.5 million BOE during the year ended December 31, 2024, resulting in a net increase of 151.5 million BOE. This increase in proved oil and natural gas reserves was primarily attributable to the Ameredev Acquisition and the Company's delineation and development operations in the Delaware Basin during 2024. The Company increased its total proved oil and natural gas reserves by 119.9 million BOE as a result of acquisitions and trades during 2024. The Company also added 99.9 million BOE in proved reserves through extensions and discoveries during 2024, of which 28.4 million BOE resulted from new well locations turned to sales during 2024 to establish proved developed reserves and 71.5 million BOE resulted primarily from new proved undeveloped locations identified as a result of drilling activities on the Company's existing acreage in the Delaware Basin during 2024. These increases were partially offset by net downward revisions of prior estimates for proved oil and natural gas reserves, which primarily included the removal of 8.2 million BOE resulting from the 4%

decrease in oil prices and the 19% decrease in natural gas prices used to estimate total proved reserves at December 31, 2024, as compared to December 31, 2023, and 15.3 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of the Company's properties in the Delaware Basin. These downward revisions at December 31, 2024 were partially offset by positive forecast updates of 21.7 million BOE.

The Company's proved oil and natural gas reserves increased 29% from 356.7 million BOE at December 31, 2022 to 460.1 million BOE at December 31, 2023. The Company's proved oil and natural gas reserves increased by 151.5 million BOE and the Company produced 48.1 million BOE during the year ended December 31, 2023, resulting in a net increase of 103.3 million BOE. This increase in proved oil and natural gas reserves was primarily attributable to the Advance Acquisition and the Company's delineation and development operations in the Delaware Basin during 2023. The Company increased its total proved oil and natural gas reserves by 109.1 million BOE as a result of acquisitions and trades during 2023. The Company also added 88.3 million BOE in proved reserves through extensions and discoveries during 2023, of which 27.6 million BOE resulted from new well locations drilled during 2023 to establish proved developed reserves and 60.7 million BOE resulted primarily from new proved undeveloped locations identified as a result of drilling activities on the Company's existing acreage in the Delaware Basin during 2023. These increases were partially offset by the removal of 17.4 million BOE resulting from the 17% decrease in oil prices and the 58% decrease in natural gas prices used to estimate total proved reserves at December 31, 2023, as compared to December 31, 2022, and the removal of 31.5 million BOE in proved undeveloped reserves that were not developed or were no longer expected to be developed within five years of their initial booking resulting primarily from changes in development plans for certain of the Company's properties in the Delaware Basin.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is not intended to provide an estimate of the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair market value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, potential improvements in industry technology and operating practices, the risks inherent in reserves estimates and perhaps different discount rates.

As noted previously, for the period from January through December 2025, the unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices were $61.82 per Bbl and $3.39 per MMBtu, respectively. For the period from January through December 2024, the comparable average oil and natural gas prices were $71.96 per Bbl and $2.13 per MMBtu, respectively. For the period from January through December 2023, the comparable average oil and natural gas prices were $74.70 per Bbl and $2.64 per MMBtu, respectively.

Future net cash flows were computed by applying these oil and natural gas prices, adjusted for all associated transportation and gathering costs, gravity and energy content and regional price differentials, to year-end quantities of proved oil and natural gas reserves and accounting for any future production, development and plugging and abandonment costs associated with producing these reserves; neither prices nor costs were escalated with time in these computations.

Future income taxes were computed by applying the statutory tax rate to the excess of future net cash flows relating to proved oil and natural gas reserves less the tax basis of the associated properties. Tax credits and NOL carryforwards available to the Company were also considered in the computation of future income taxes. Future net cash flows after income taxes were discounted using a 10% annual discount rate to derive the standardized measure of discounted future net cash flows.

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SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

The following table presents the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2025, 2024 and 2023 (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Future cash inflows	$ 27,159,063	$ 29,033,021	$ 23,662,653
Future production costs	(10,126,010)	(10,126,454)	(7,623,205)
Future development costs	(2,683,388)	(2,705,340)	(2,162,625)
Future abandonment costs	(236,163)	(158,346)	(93,901)
Future income tax expense	(2,089,975)	(3,326,489)	(2,939,514)
Future net cash flows	12,023,527	12,716,392	10,843,408
10% annual discount for estimated timing of cash flows	(5,036,961)	(5,339,842)	(4,729,916)
Standardized measure of discounted future net cash flows	$ 6,986,566	$ 7,376,550	$ 6,113,492

The following table summarizes the changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2025, 2024 and 2023 (in thousands).

	Year Ended December 31,		
	2025	2024	2023
Balance, beginning of period	$ 7,376,550	$ 6,113,492	$ 6,983,203
Net change in sales and lifting costs related to future production	(1,298,014)	(915,645)	(3,074,085)
Changes in estimated future development costs	5,096	(706,728)	(504,323)
Sales and transfers of oil and natural gas produced during the period	(2,757,200)	(2,496,524)	(2,037,451)
Net purchases of reserves in place	82,713	2,310,776	2,113,620
Net change due to extensions and discoveries	1,376,044	1,925,926	1,711,389
Net change due to revisions in estimates of reserves quantities	(52,151)	(102,776)	(890,794)
Previously estimated development costs incurred during the period	821,212	685,163	441,671
Accretion of discount	923,378	770,407	807,896
Changes in timing and other	(97,104)	15,190	3,913
Net change in income taxes	606,042	(222,731)	558,453
Standardized measure of discounted future net cash flows	$ 6,986,566	$ 7,376,550	$ 6,113,492